BOHOL II ELECTRIC COOPERATIVE, INC.

Cantagay, Jagna, Bohol

DISTRIBUTION DEVELOPMENT PLAN

(Year 2016-2025)

PREPARED BY:
BOHECO II-TECHNICAL WORKING GROUP

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1.1 BOHECO II PROFILE

Figure 1-1. BOHECO I Coverage Area

Bohol II Electric Cooperative, Inc. (BOHECO II), an integral part of the economic engine of Bohol, is a non-stock, non-profit entity incorporated in the Philippines to operate an electric power supply and distribution service. Its official headquarter is located at Cantagay, Jagna, Bohol. BOHECO-II was organized in May 13, 1978 with the first load energized in March 7, 1980. It has been granted a franchise that covers the northeast portion of Bohol, with an approximate topographical area of 2,101 square kilometers. Its Certificate of Franchise was granted last June 11, 1980. Since then, it has been providing electric power distribution service to 9 districts, 491 barangays & 21 municipalities, including the island municipality of Pres. Carlos P. Garcia. As of 2015, BOHECO-II is categorized by NEA as an AAA, Mega-Large electric cooperative.

The Vision of BOHECO II is to be *"a leading electric power utility providing excellent service towards consumer's welfare"*, while its mission is *"to provide reliable services to all member-consumer; to energize potential connection within the franchise area; and to ensure equal protection of consumer-rights.*

BOHECO II Offices and Service Facilities:

Offices	Description	Location
Main Area Office	Main Office	Cantagay,Jagna
Ubay Area Office	Area Office	Bood, Ubay
Talibon Area Office	Area Office	San Jose, Talibon
Alicia Satellite Offices	Collection Offices	Poblacion, Alicia

BOHECO II Board of Directors:

Name of Director	BOD Designation	Area Represented
Dionesio C. Olaivar Jr.	President	Ubay/CPG Island
Virginia B. Item	1st Vice President	Talibon/Trinidad/Bien Unido
Ruel E. Mabaquiao	2nd Vice President	Pilar/Sierra Bullones
Christine G. Lagura	Secretary	Guindulman/Anda
Candelario C. Bag-O	Treasurer	Duero/Jagna
Rodulfo O. Tutor	Auditor	Mabini/Alicia/Candijay
Cristita A. Cericos	Chief PRO	San Miguel/Dagohoy/Danao
Princess Ella L. Torcende	PRO II	Getafe/Buenavista
Santos G. Ubota	PRO I	Garcia Hernandez/Valencia
Msgr. Orencio D. Jubac	NEA Independent BOD	
Evangelito S. Estaca	Consultant	

BOHECO II Management and Staff:

Name	Position/Department
Eugenio R. Tan (REE, MPA)	General Manager
Saturnino A. Forones (CPA)	Finance Services Dept. Manager
Tito O. Andamon (BS EE, MPA)	Institutional Service Dept. Manager
Noel M. Aleman (REE, MPA)	Technical Services Dept. Manager
Vidal A. Pagaran (RMechE, MPA)	Ubay Area Dept. Manager
Joseph Musong (BS CE,MBA)	Talibon Area Dept. Manager
Colita C. Baldon (BSC,MPA)	Internal Auditor

1.2 HISTORICAL DATA

1.2.1 Kilometers of Distribution Line

BOHECO-II operates and maintains 0.355km of 69kV sub-transmission line, 1,401 km of 13.2/7.62kV primary line and 1,762.6 km of secondary lines with a nominal voltage of 230V as shown in Table 1.1 and Figure 1-2.

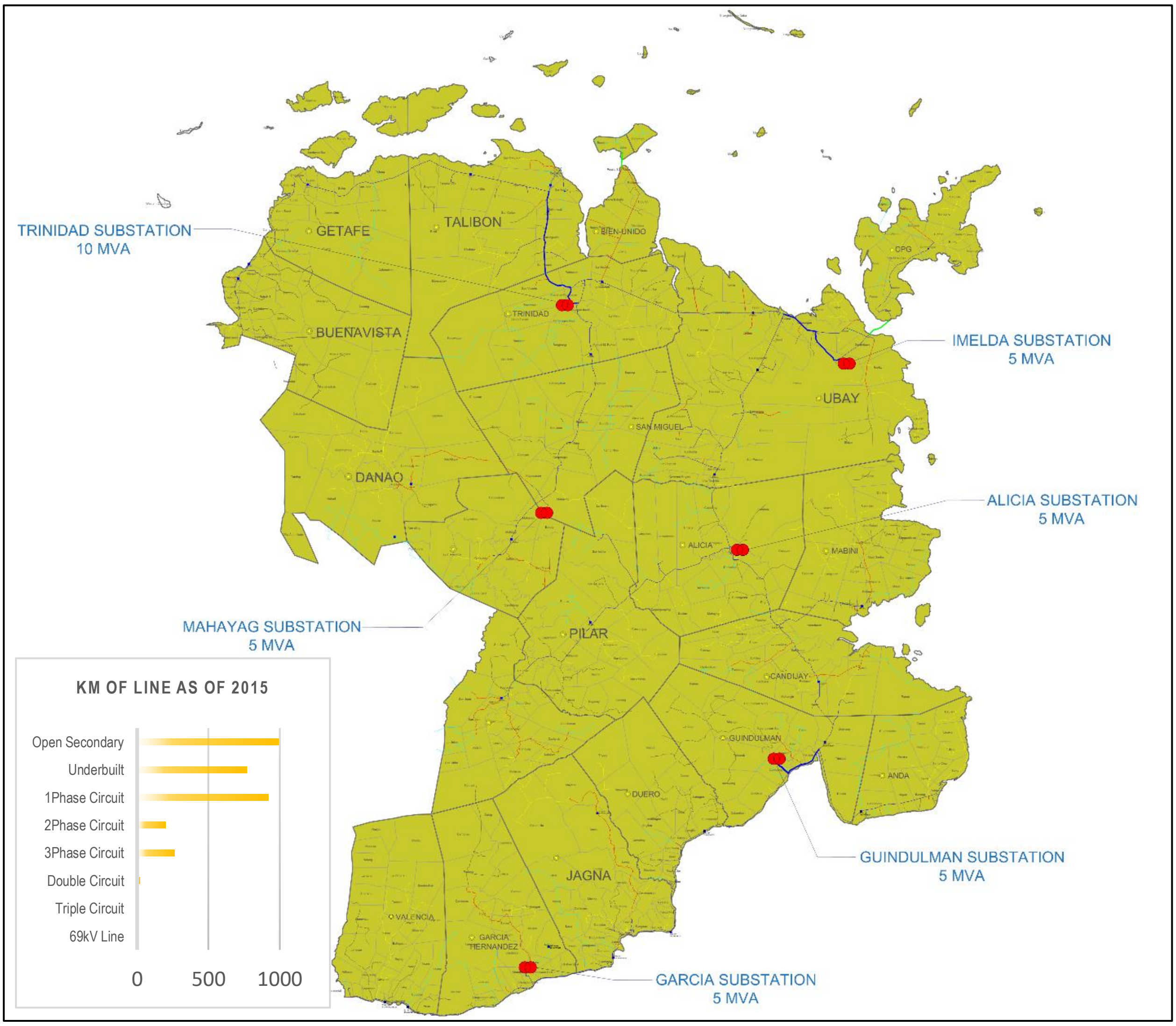


Figure 1-2. BOHECO II Distribution System Map

Distribution Line Description	2011	2012	2013	2014	2015
69kV Line	0.355	0.355	0.355	0.355	0.355
Triple Circuit	1.5	1.5	1.5	1.5	1.5
Double Circuit	14.87	20.611	20.611	20.611	20.611
3Phase Circuit	247.296	247.838	248.171	257.436	261.107
2Phase Circuit	196.164	197.056	197.79	197.86	198.571
1Phase Circuit	746.649	793.536	863.522	885.245	919.152
Underbuilt	651.774	671.476	718.272	742.537	768.733
Open Secondary	633.825	702.385	862.719	926.664	993.848

Table 1-1.Cumulative Distribution Line Length

1.2.1 Consumer and Sales Profile

BOHECO II's current mix of customers served is shown in Table 1-2. It is largely Residential at 91% *(50 % at Mainland and 41 % Residential from BAPA&ECA)*, and the rest are Commercial at 4%, Public Buildings at 2%, Street Lighting at 2%, and Industrial Loads at less than 1%. The current average energy consumption per customer type is also presented in Figure 1-3 where it is shown that the residential customers draw the largest part of the total energy requirements at 64%, and the remaining energy requirement is for Commercial at 12%, Street Lighting at 1%, Public Buildings at 8%, and Industrial Loads at 13%.

CLASSIFICATIONS	Consumer Type	SALES		CONSUMER SERVED	
		KWHR	%	Number	KWHR
	Residential	39,369.83	46%	55,986	50%
	BAPA & ECA	15,895.68	18%	45,507	41%
	Commercial	10,310	12%	4,504	4%
	Industrial	10,904.83	13%	319	0.29%

	Public Building	6974	8%	2,175	2%
	Street Light	783	1%	2,764	2%
HIGH VOLTAGE	Industrial	2,167.40	3%	3	0.003%
TOTAL		**86,404.74**	**100%**	**111,258**	**100%**

Table 1-2. 2015 Sales and Consumer profile

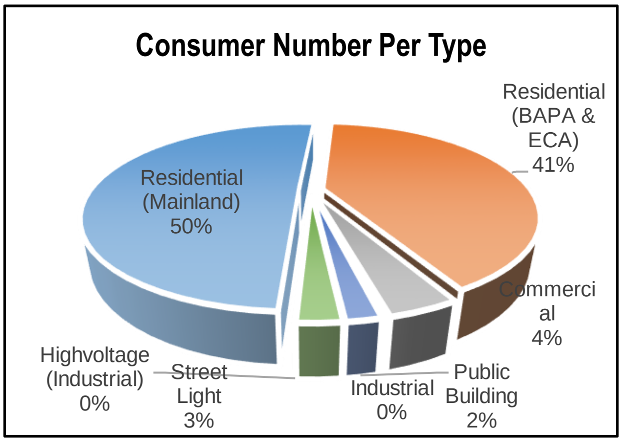


Figure 1-3. 2015 Consumer per type percentage

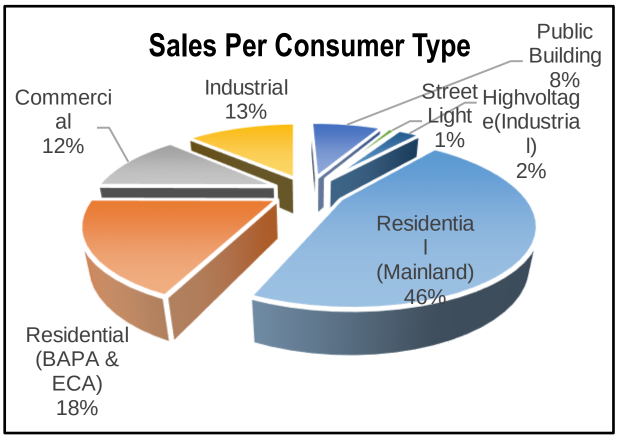


Figure 1-4. 2015 Sales per type percentage

Description	ENERGY AND DEMAND PROFILE (HISTORICAL DATA)						
	2009	2010	2011	2012	2013	2014	2015
Energy Purchased (GWh)	63,298	69,302	72,911	80,604	81,580	87,062	95,496
Energy Sales (GWh)	56,473	61,213	64,657	71,891	73,088	78,073	86,405
Coincident Demand(MW)	14.63	16.06	16.66	17.57	18.33	19.46	18.87
Utility used (kWh)	134,457	137,351	112,200	133,071	133,343	150,269	171,321
Load Factor (%)	54%	49%	51%	53%	52%	52%	58%
Power Factor (%)	90.5%	98.6%	99.5%	99.6%	99.5%	99.7%	99.8%
System Loss (%)	10.78%	11.67%	11.32%	10.81%	10.41%	10.32%	9.52%

Table 1-3. BOHECO II Energy and Demand Historical Data

1.2.2 Capacity Data

BOHECO II has six substations with a total capacity of 32.5 MVA namely: Garcia Substation, Guindulman Substation, Alicia Substation, Trinindad Substation, Imelda Substation and Mahayag Substation. These substations are connected to two 100-MVA NGCP Transmission Substations located in Imelda, Ubay and Sambog, Corella.

In the year 2015, BOHECO II had a coincidental peak demand of 18.87 MW and a non-coincidental peak demand of 20.13 MW at 58% load factor. Table 1-4 and Figure 1-4 show the substation capacity loading as a percentage of their maximum rated MVA capacity.

YEAR	GARCIA SUBSTATION (Calma, Garcia Hernandez)		GUINDULMAN SUBSTATION (Pandayan, Guindulman)		ALICIA SUBSTATION (Progreso, Alicia)		TRINIDAD SUBSTATION (Tawid Pob., Trinidad)		IMELDA SUBSTATION (Imelda, Ubay)		MAHAYAG SUBSTATION (Mahayag, San Miguel)	
	Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)	
	Load Forecast		Load Forecast		Load Forecast		Load Forecast		Load Forecast		Load Forecast	
	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%
2009	3.05	50%	1.88	31%	2.70	44%	3.59	29%	2.14	35%	1.14	37%
2010	3.04	50%	2.08	34%	2.88	47%	3.85	31%	3.16	52%	1.20	39%
2011	3.65	60%	2.15	35%	3.08	50%	4.03	33%	3.41	56%	1.25	41%
2012	3.42	56%	2.19	36%	3.61	59%	4.36	36%	3.73	61%	1.27	41%
2013	3.39	55%	3.21	52%	3.94	64%	4.88	40%	3.96	65%	1.80	59%
2014	3.41	56%	2.33	38%	3.56	58%	4.94	40%	3.19	52%	1.45	47%
2015	**3.54**	**58%**	**3.02**	**49%**	**3.71**	**61%**	**5.20**	**42%**	**3.15**	**51%**	**1.51**	**49%**

Table 1-4. Historical substation Loading Details

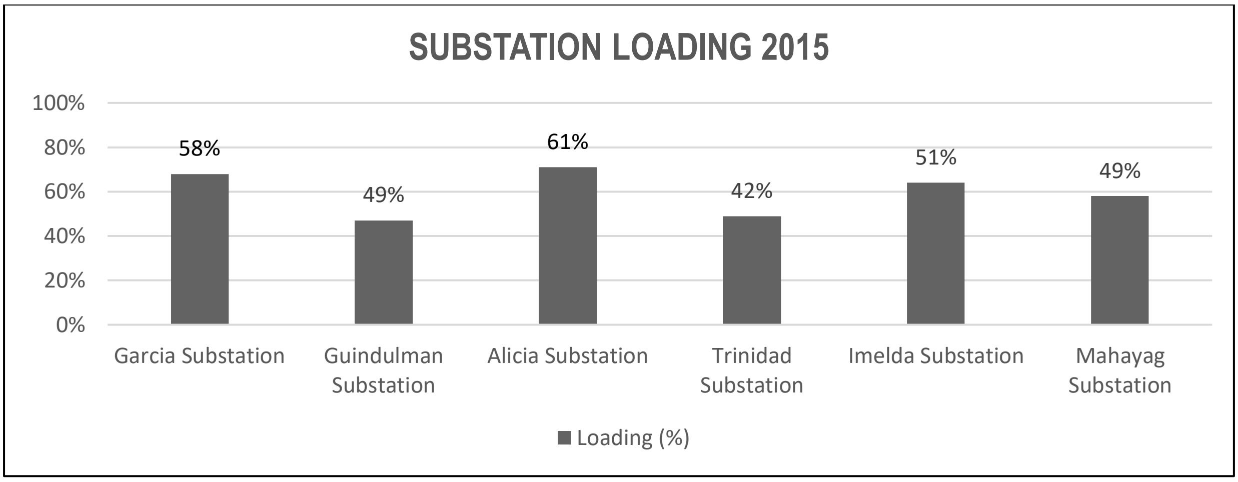


Figure 1-5. 2015 Substation Loading Graph

1.2.3 Reliability Data

BOHECO II maintains the reliability of its distribution system at acceptable levels and standards as prescribed in the Philippine Distribution Code: the System Average Interruption Frequency Index (**SAIFI)** should be at a maximum of 20 customer-interruptions per customer-year and the System Average Interruption Duration Index (**SAIDI)** should be no more than 45 hours per customer-year, to provide service to its customers at a satisfactory level of reliability. In 2015, BOHECO II recorded a SAIFI of 6.54 interruptions per customer-year, a SAIDI of 8.28 hours of interruption per customer-year, and a MAIFI of 17.06 momentary interruptions per customer-year.

1.2.1 Efficiency Data

Shown in Figure 1-6 is the graphical representation of BOHECO II's Historical System Loss. For more than 10 years, BOHECO II has maintained its yearly average System Loss below the 13% System Loss Cap prescribed by the Energy Regulatory

Commission (ERC). BOHECO II's System Loss has been steadily decreasing over the years. In 2015 its system loss was at 9.52%; a vast improvement from its 18.01% System Loss level way back in year 2002.

Figure 1-6 Historical System Loss

Table 1-6 shows the segregated Technical Loss components from 2009 – 2015. It shows the average percentage share of each component: 36 % of the total Technical Loss is due to Primary Line Loss, 21% due to No-Load Loss and Load Loss of Transformers, 20% for Substation Loss, 16% Secondary Line Loss, 7% kWh Meter Loss, and 0.116% Line Devices/Equipment losses.

Year	Substation Losses (kWh)	MV Line Losses (kWh)	Line Transformer Losses (kWh)	LV Line Losses (kWh)	Line Devices/ Equipment Losses (kWh)	Metering Losses (kWh)
2009	1,101,222.46	2,070,247.80	1,374,062.53	849,674.48	9,558.00	516,288.96
2010	1,201,174.23	2,331,644.96	1,432,601.41	980,980.18	9,007.20	540,823.04
2011	2,585,385.27	2,399,063.73	1,449,050.77	1,041,120.14	8,672.99	550,269.28
2012	2,567,495.10	2,902,101.54	1,581,678.46	1,277,467.84	8,748.65	580,332.36
2013	1,534,669.76	3,018,308.74	1,585,651.86	1,322,383.59	8,756.19	589,026.90
2014	927,145.67	3,322,297.30	1,808,535.65	1,442,388.37	8,035.85	665,734.34
2015	936,246.19	3,977,117.10	2,070,744.96	1,695,935.41	10,628.39	596,617.81
Percentage Shared	**20%**	**36%**	**21%**	**16%**	**0.116%**	**7%**

Table 1-5 Percentage shared of Technical Loss component

Chapter 2: DISTRIBUTION DEVELOPMENT PLANNING PERSPECTIVE

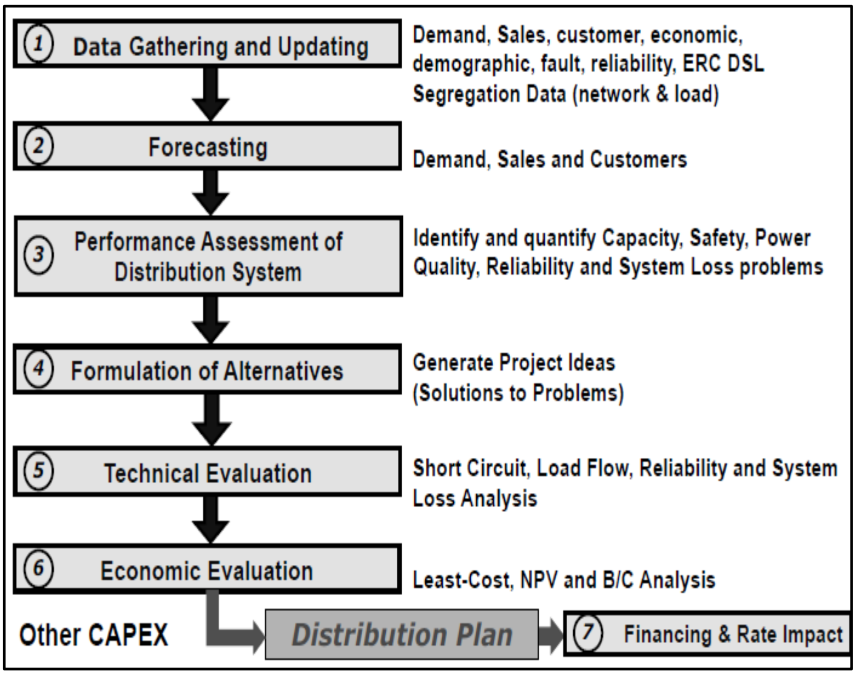


Figure 2-1. Distribution Planning Procedure

A Distribution Development Plan aims to achieve an orderly and economical development of the distribution system that will identify least-cost projects that will ensure the it satisfies minimum standard requirements in apacity, reliability, efficiency and power quality set forth in the Philippine Distribution Code (PDC) and safey requirements specified in the Philippine Electrical Code (PEC). Adherence to these requirements of the PDC and PEC ensures that BOHECO II's consumers are provided reliable, efficient, safe, and quality power suppply. Figure 2-1 outlines the systematic process for coming up with the Distribution Development Plan and the Capital Expenditure projects.

2.1 Data Gathering and Updating

Distribution system data are considered the center of planning and all activities of the distribution utility. BOHECO II implements a systematic process of data gathering, inspection and record keeping to capture all necessary information from the substation to the end consumers. The accuracy of results of studies and simulations used for the distribution development planning is highly dependent on the accuracy and integrity of the data gathered.

2.2 Forecasting

BOHECO–II's forecasting methodology employs trend analysis using multi-variable regression models. With the available data—historical energy sales and demand, a mathematical and statistical "line fitting" or "curve fitting" technique is used in order to come up with scientifically valid, accurate and acceptable forecasting models. The model that provides the best fit and passes all the validity and accuracy tests shall be used. Figure 2-2 shows a flowchart for the load forecasting methodology. The statistical tests shown in Figure 2-2 are used to measure the validity and accuracy of the forecast model.

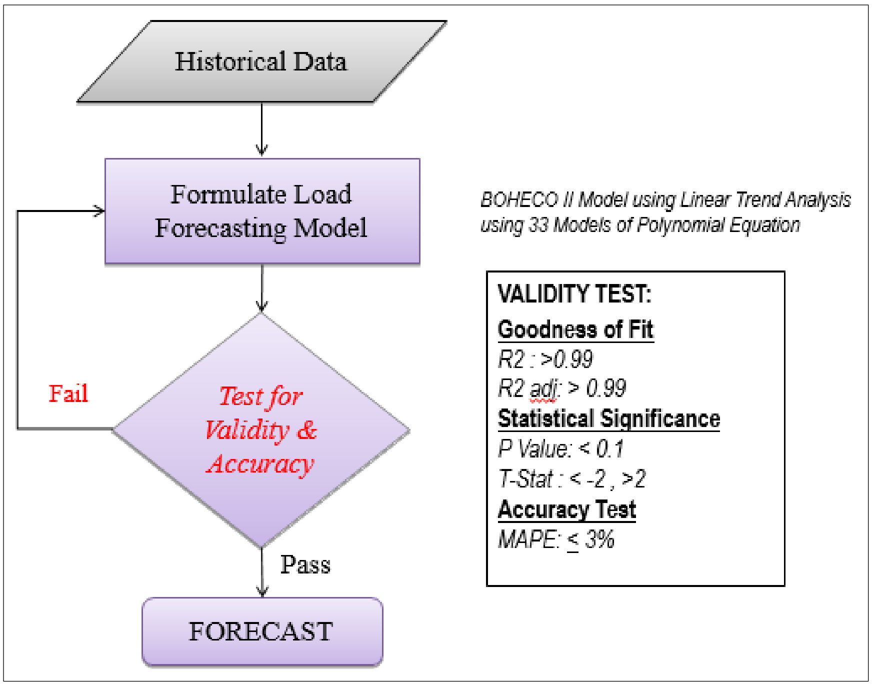


Figure 2-1. Forecasting Methodology

The peak demand forecast is derived from the forecasted system energy by dividing the forecasted energy by the product of the Load Factor and the total number of hours in a year (8,760 hours) as shown in Equation 1. BOHECO II used the system load factor from the hourly load data provided by NGCP for the year 2015.

Equation 1. System Demand Formula

$$\boldsymbol{Demand}_{system} = \frac{Energy\ Forecast_{system}}{\boldsymbol{L.F}_{system} \times \mathbf{8760}}$$

2.3 Performance Assessment

The assessment of the existing as well as the future distribution system is carried out to quantify problems in the distribution system that need to be solved. This includes the performance assessment of the system in terms of sufficiency of capacity, adherence to safety standards, power quality, reliability and efficiency of the distribution system. The performance of the distribution system is compared to the standards set forth in the Philippine Grid and Distribution Code and the Philippine Electrical Code.

2.4 Formulation of Alternatives

After quantifying the problems in the distribution system, the next step is to formulate two or more alternatives solution to improve the performance of the system to comply with the standards/criteria set forth in the PGC, PDC, and PEC. BOHECO

II used Distribution system applied software (DSAS_DSL) as simulator software to evaluate and analyze the results. Software are used to validate if the given alternative solutions are technically feasible and can solve the problem identified.

2.5 Technical Evaluation

BOHECO II follows the procedures in the Electric Cooperative Distribution Utility Planning Manual 2009 and is guided by the standards provided in the PGC, PDC, and the PEC. We describe below the technical analyses conducted and the different criteria used for evaluating proposed solutions. Solutions that pass the criteria are called technically feasible solutions that can solve the problems identified.

A. Capacity Analysis: The total substation capacity of the distribution system must meet the system peak demand. Since it takes time to procure and build new substation capacity, substation power transformers with loading greater than 70% of its total rated capacity shall trigger the addition of new substation capacity so that new capacity will be operational before existing substation loads exceed their total capacity.

B. Voltage Analysis: To ensure the quality of power delivered to customers, the voltage of the distribution system must be maintained within +/- 10% of the nominal system voltage and a maximum unbalance of 2.5%. The voltage profile of all feeders of the distribution system, up to the end-user or consumers must be examined.

C. Safety Analysis: The short circuit duty of all protective devices must be at least *110%* of the maximum available fault. Also, minimum faults which usually occur at the far end of the feeder, must be sensed and isolated by protective devices. For purposes of calculating the minimum fault current, a fault resistance of 30 ohms in MV feeders are used.

D. Reliability Analysis: Historical reliability and predicted reliability of the distribution system are evaluated against the reliability criteria in the PDC. The reliability of the distribution system must adhere to a SAIFI of a maximum of 20 customer-interruptions per customer-year and SAIDI at a maximum of 45 hours per customer-year.

E. Efficiency Analysis: The segregated system loss of the distribution system for the existing and future systems are determined. The segregated system loss analysis will assist the distribution engineer in identiying which parts of the distribution system contributes the most losses and requires a solution. The total system loss of the distribution system must not exceed the ERC System Loss CAP equal to 13%.

2.6 Economic Evaluation

Economic evaluation is done to ensure the optimal least-cost project is implemented. The problems of the distribution system can be solved through a number of project alternatives that are considered technically feasible. Each technically feasible project alternative is subjected to economic evaluation where the initial costs as well as the recurring costs are compared so that the lifetime cost of the selected project will provide the least-cost solution.

In the technical analyses and evaluation, technically feasible solutions or projects may be classified into Mandatory or Optional Projects. For Mandatory Projects, the economic evaluation used shall be “least-cost” project. The project chosen to be implemented is the project whose cost has the lowest Net Present Value (NPV). For Optional Projects, the technically feasible project will only be chosen and implemented if the project has a Benefit-Cost-Ratio greater than 1 or a positive Net Present Value (NPV). All project alternatives are compared using the present worth or present value of the life cycle costs.

2.7 Financial and Rate Impact Analysis

Financial Analysis of the proposed least-cost projects are conducted to determine the sufficiency of the approved ERC RFSC rates to cover the payments for existing loans as well as additional loans that will fund the proposed projects for the CAPEX period. Rate Impact Analysis is also done to determine if the capex projects will necessitate an increase in the rates and to analyze whether this rate increase is justifiable to be passed on to consumers. If the rate increase it too high or if the cashflow of the EC becomes unsustainable, then some projects may be scheduled, prioritized or deferred to minimize its impact to consumers and to the viability of the EC.

Chapter 3: PERFORMANCE ASSESSMENT OF DISTRIBUTION SYSTEM

3.1 FORECASTING

3.1.1 Energy Forecasting

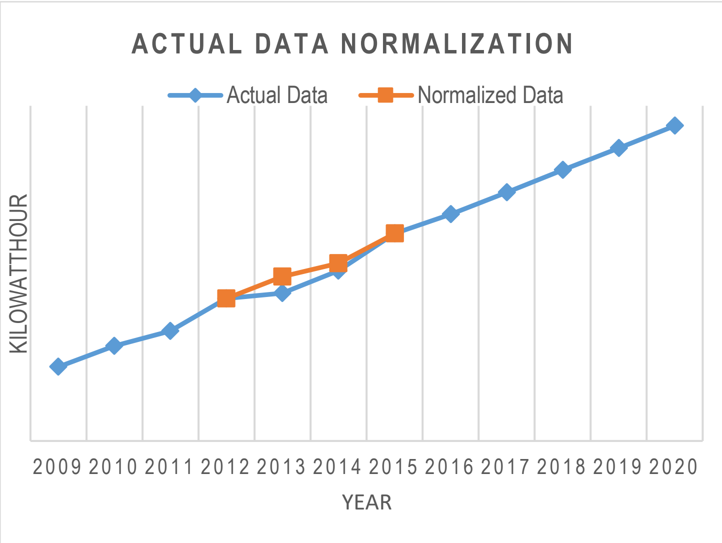


Figure 3-1. Normalized and Actual Raw Data (energy).

BOHECO-II came up with thirty-three (33) mathematical forecasting models to represent the trend of the historical energy Sales (see annex B). Using the forecasting methodology discussed in Chapter 2, BOHECO-II selects the best fit forecasting model. Initially, none of the models passed the validity and accuracy tests prescribed in our forecasting methodology when we used the raw historical data gathered. After several validation of the data, we concluded that the month-long outage and other effects of supertyphoon Yolanda, disturbed the normal historical trend of electricity consumption in BOHECO II. To take this into account, we normalized the historical data as shown in Figure 3-1 and Table 3-1. By using the historical monthly growth rate of BOHECO II sales, we came up with the estimated value to normalize the affected sales from the month of November 2013 to February 2014.

BOHECO II forecasted energy sales using the *normalized data* using both per component forecasting and direct forecasting methods. Table 3-2 shows the forecasted energy in MWH and the average growth rate result of two methods.

In validating the results of the two methods, BOHECO II chose the direct forecasting of the data for the simulation of distribution system's future performance. The forecasted accuracy test results are found in Annex C.

MONTH	YEAR 2013		YEAR 2014	
	Actual Data	Normalize Data	Actual Data	Normalize Data
January	5,908,665.42	5,908,665.42	5,384,061.59	6,391,238.79
February	5,838,425.44	5,838,425.44	5,598,957.07	6,301,616.13
March	6,157,602.68	6,157,602.68	5,831,947.20	5,831,947.20
April	6,878,165.23	6,878,165.23	6,892,977.32	6,892,977.32
May	7,330,198.01	7,330,198.01	7,619,045.20	7,619,045.20
June	6,737,048.16	6,737,048.16	7,109,563.89	7,109,563.89
July	6,342,382.01	6,342,382.01	6,502,207.72	6,502,207.72
August	6,556,262.73	6,556,262.73	6,732,550.47	6,732,550.47
September	6,506,563.00	6,506,563.00	6,536,650.52	6,536,650.52
October	6,034,512.42	6,034,512.42	6,645,158.96	6,645,158.96
November	2,850,936.21	5,879,849.93	6,747,079.32	6,747,079.32
December	5,946,898.41	6,545,028.00	6,473,255.65	6,473,255.65
Total	**73,087,659.74**	**76,714,703.04**	**78,073,454.91**	**79,783,291.17**

Table 3-1. Normalization of Historical Data

FORECAST METHOD	FORECASTED SALES (MWH)										AGR
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
	87,726	92,197	96,567	100,850	105,058	109,201	113,288	117,326	121,321	125,278	
		5%	*5%*	*4%*	*4%*	*4%*	*4%*	*4%*	*3%*	*3%*	
	90,844	95,795	100,745	105,695	110,645	115,595	120,545	125,496	130,446	135,396	
		5%	5%	5%	5%	4%	4%	4%	4%	4%	

Table 3-2. Per Component and Direct Forecasting Method

3.1.1.1 Forecasted Sales Energy per Feeder (MWh)

The forecasted energy sales per feeder was derived from the total energy forecast in Table 3-2 by allocating them to each feeder in proportion to its historical energy sales. Table 3-3 summarizes the per feeder energy forecast.

Feeder	FORECASTED SALES (MWH)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	9,368	9,694	10,024	10,359	10,697	11,038	11,381	11,726	12,072	12,420
SAF2	6,247	6,566	6,888	7,212	7,538	7,864	8,192	8,521	8,850	9,180
SAF3	1,072	1,119	1,165	1,210	1,254	1,296	1,337	1,378	1,417	1,456
SBF1	3,782	4,065	4,367	4,686	5,025	5,383	5,760	6,158	6,577	7,016
SBF2	3,591	3,720	3,845	3,968	4,087	4,203	4,317	4,428	4,536	4,641
SBF3	3,640	3,752	3,861	3,968	4,073	4,175	4,275	4,373	4,468	4,561
SCF1	8,882	9,658	10,448	11,251	12,065	12,890	13,724	14,567	15,419	16,278
SCF2	8,864	9,241	9,607	9,962	10,308	10,644	10,972	11,291	11,603	11,906
SDF1	7,167	7,466	7,756	8,038	8,312	8,579	8,839	9,092	9,339	9,580
SDF2	12,084	12,713	13,340	13,966	14,590	15,212	15,831	16,449	17,064	17,677
SDF3	5,216	5,588	5,962	6,338	6,716	7,096	7,476	7,859	8,242	8,626
SDF4	1,057	1,105	1,151	1,196	1,240	1,282	1,324	1,364	1,403	1,441
SEF1	3,786	4,000	4,207	4,407	4,601	4,789	4,971	5,149	5,322	5,491
SEF2	1,958	2,070	2,179	2,284	2,386	2,485	2,581	2,675	2,766	2,855

SEF3	7,959	8,537	9,116	9,697	10,280	10,863	11,448	12,033	12,619	13,205
SFF1	1,722	1,797	1,869	1,939	2,008	2,074	2,139	2,202	2,263	2,323
SFF2	2,605	2,709	2,810	2,909	3,005	3,098	3,189	3,278	3,364	3,448
SFF3	1,845	1,994	2,147	2,303	2,463	2,624	2,788	2,954	3,122	3,292
TOTAL	**90,844**	**95,795**	**100,745**	**105,695**	**110,645**	**115,595**	**120,545**	**125,496**	**130,446**	**135,396**

Table 3-3. Forecasted Sales per Feeder

3.1.1.2 Forecasted Demand (MW)

Table 3-4 summarises the 10-year forecasted demand per substation (in MW) which is derived by dividing the energy forecast by the system load factor and the total number of hours in a year.

$$\boldsymbol{Demand}_{system} = \frac{Energy\ Forecast_{system}}{\boldsymbol{L.F}_{system}\times\mathbf{8760}}\text{, } where\ 2015\ Load\ Factor\ (LF) = 0.58$$

SUBSTATION	Rated MVA	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Garcia Substation	5/6.25	3.85	4.02	4.18	4.34	4.50	4.67	4.83	5.00	5.16	5.33
Guindulman Substation	5/6.25	3.35	3.44	3.59	3.76	3.93	4.10	4.27	4.45	4.64	4.83
Alicia Substation	5/6.25	4.23	4.42	4.69	4.96	5.23	5.50	5.77	6.05	6.32	6.59
Trinidad Substation	10/12.5	5.66	5.84	6.13	6.41	6.70	6.98	7.27	7.55	7.83	8.10
Imelda Substation	5/6.25	3.13	3.27	3.47	3.66	3.86	4.05	4.25	4.44	4.63	4.82
Mahayag Substation	2.5/3.125	1.65	1.70	1.78	1.87	1.95	2.04	2.12	2.20	2.29	2.37

Table 3-4. Forecasted Loading per Substation

3.1.2 Forecasted number of consumers

Table 3-5 shows the forecasted number of consumers per customer type. Details of the forecast can be found in Annex B.

Consumer Type	FORECASTED NO. OF CONSUMER									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RESIDENTIAL										
Residential	58,769	61,312	63,804	66,256	68,670	71,046	73,395	75,712	78,005	80,272
BAPA & ECA	47,769	49,835	51,863	53,855	55,816	57,749	59,657	61,541	63,404	65,248
LOW VOLTAGE										
Commercial	4,728	4,932	5,133	5,330	5,524	5,716	5,904	6,091	6,275	6,458
Industrial	335	349	364	378	391	405	418	431	444	457
Public Building	2,283	2,382	2,479	2,574	2,668	2,760	2,851	2,941	3,030	3,118
Street Light	2,901	3,027	3,150	3,271	3,390	3,508	3,623	3,738	3,851	3,963
HIGHVOLTAGE										
Industrial	3	3	3	3	3	3	3	3	3	3
TOTAL	**116,788**	**121,840**	**126,796**	**131,667**	**136,462**	**141,187**	**145,851**	**150,457**	**155,012**	**159,519**

Table 3-5. Consumer Forecast Summary

3.2 Capacity Analysis

We conducted Capacity Analysis of existing substations as well as new substations already proposed in previous Capex applications. The percentage loading of Garcia substation is significantly reduced in 2016 due to transfer of a portion of its load to a new substation in Catagay, Jagna due for operation in 2017.

The uprating of Mahayag Substation will accommodate future capacity requirements. The highlighted cells represent loading of substations in excess of the prescribed loading levels. When loading levels in a substation exceed 70%, it is time to trigger the procurement and building of a new substation. As shown in Table 3-6, new substations will be required in the year 2023.

YEAR	GARCIA SUBSTATION		CANTAGAY SUBSTATION (New)		GUINDULMAN SUBSTATION		ALICIA SUBSTATION		TRINIDAD SUBSTATION		IMELDA SUBSTATION		MAHAYAG SUBSTATION (Uprate to 5MVA @ 2017)	
	Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)		Max Rating (5/6.25MVA)	
	Load Forecast		Load Forecast		Load Forecast		Load Forecast		Load Forecast		Load Forecast		Load Forecast	
	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%
2016	3.93	60%			3.41	55%	4.32	69%	5.77	46%	3.19	51%	1.68	54%
2017	2.19	34%	1.90	29%	3.51	56%	3.38	54%	5.95	48%	3.33	53%	2.86	46%
2018	2.29	35%	1.97	30%	3.67	59%	3.56	57%	6.25	50%	3.54	57%	3.04	49%
2019	2.39	37%	2.03	31%	3.83	61%	3.75	60%	6.55	52%	3.74	60%	3.22	52%
2020	2.49	38%	2.10	32%	4.01	64%	3.93	63%	6.84	55%	3.94	63%	3.40	54%
2021	2.59	40%	2.17	33%	4.18	67%	4.11	66%	7.13	57%	4.14	66%	3.59	57%
2022	2.70	41%	2.24	34%	4.36	70%	4.29	69%	7.42	59%	4.33	69%	3.77	60%
2023	2.80	43%	2.30	35%	4.54	73%	4.47	71%	7.70	62%	4.53	72%	3.95	63%
2024	2.90	45%	2.37	36%	4.73	76%	4.64	74%	7.99	64%	4.72	76%	4.14	66%
2025	3.00	46%	2.44	38%	4.93	79%	4.82	77%	8.27	66%	4.91	79%	4.32	69%
2026	3.10	48%	2.51	39%	5.12	82%	5.00	80%	8.55	68%	5.11	82%	4.50	72%
2027	3.20	49%	2.58	40%	5.33	85%	5.17	83%	8.83	71%	5.30	85%	4.69	75%
2028	3.30	51%	2.65	41%	5.54	89%	5.35	86%	9.11	73%	5.48	88%	4.87	78%
2029	3.40	52%	2.71	42%	5.75	92%	5.52	88%	9.38	75%	5.67	91%	5.06	81%
2030	3.50	54%	2.78	43%	5.97	96%	5.69	91%	9.65	77%	5.86	94%	5.24	84%
2031	3.60	55%	2.85	44%	6.20	99%	5.86	94%	9.93	79%	6.04	97%	5.43	87%
2032	3.70	57%	2.92	45%	6.43	103%	6.03	97%	10.20	82%	6.22	100%	5.61	90%
2033	3.79	58%	2.99	46%	6.66	107%	6.20	99%	10.46	84%	6.40	102%	5.80	93%
2034	3.89	60%	3.06	47%	6.91	111%	6.37	102%	10.73	86%	6.58	105%	5.98	96%
2035	3.99	61%	3.13	48%	7.15	114%	6.54	105%	10.99	88%	6.76	108%	6.17	99%
2036	4.09	63%	3.20	49%	7.41	119%	6.70	107%	11.26	90%	6.94	111%	6.35	102%

2037	4.19	64%	3.26	50%	7.67	123%	6.87	110%	11.52	92%	7.12	114%	6.54	105%
2038	4.28	66%	3.33	51%	7.93	127%	7.04	113%	11.78	94%	7.29	117%	6.72	108%
2039	4.38	67%	3.40	52%	8.21	131%	7.20	115%	12.03	96%	7.47	120%	6.90	110%
2040	4.48	69%	3.47	53%	8.48	136%	7.36	118%	12.29	98%	7.64	122%	7.09	113%
2041	4.58	70%	3.54	54%	8.77	140%	7.52	120%	12.54	100%	7.81	125%	7.27	116%
2042	4.67	72%	3.61	55%	9.06	145%	7.69	123%	12.80	102%	7.98	128%	7.45	119%
2043	4.77	73%	3.67	57%	9.35	150%	7.85	126%	13.05	104%	8.15	130%	7.64	122%
2044	4.86	75%	3.74	58%	9.65	154%	8.01	128%	13.30	106%	8.32	133%	7.82	125%

Table 3-6. Forecasted Capacity Requirements

3.3 Power Quality Analysis

The performance of the distribution system with respect to Power Quality is analysed by simulating the voltage performance of each feeder during peak hours. The voltage in all buses of the distribution system must be within +/- 10% of the nominal voltage as prescribed in the PDC.

Table 3-7 below shows the simulated per unit value of voltages. Per unit values lower than 0.9 p.u. and higher than 1.1 p.u. indicate that the voltage is beyond the standard range stated in Philippines Distribution Code (see Annex B). For feeders with undervoltages, projects such as upgrading of conducter size, transfer of loads to other substations, capacitor placement, etc… may be proposed. Also, voltage unbalance must be maintained at less than 2.5%. For feeders with voltage unbalance greater than 2.5% , simple load balancing or load transfers may be done. If load balancing does not solve the problem, conversion of some single phase or v phase circuits to three-phase may be needed. Table 3-8 summarizes the voltage unbalance in all feeders of the distribution system.

Substation	Feeder	Phase	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
		Phase A	0.86	0.86	0.86	0.85	0.85	0.84	0.84	0.84	0.84	0.84
		Phase B	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92
		Phase C	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90
		Minimum	0.86	0.86	0.86	0.85	0.85	0.84	0.84	0.84	0.84	0.84
		Phase A	0.84	0.85	0.84	0.83	0.82	0.81	0.80	0.79	0.79	0.77
		Phase B	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95	0.94	0.94
		Phase C	0.86	0.86	0.86	0.85	0.84	0.83	0.82	0.81	0.80	0.79
		Minimum	0.84	0.85	0.84	0.83	0.82	0.81	0.80	0.79	0.79	0.77
		Phase A	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase B	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase C	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96
		Minimum	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96
		Phase A	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
		Phase B	0.97	0.97	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95
		Phase C	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Minimum	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
		Phase A	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96
		Phase B	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
		Phase C	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95
		Minimum	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
		Phase A	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96
		Phase B	0.99	0.99	0.99	0.99	0.97	0.98	0.98	0.98	0.98	0.98
		Phase C	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Minimum	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96
		Phase A	0.83	0.83	0.82	0.82	0.82	0.81	0.81	0.81	0.80	0.80
		Phase B	0.87	0.87	0.87	0.87	0.87	0.86	0.86	0.86	0.86	0.86

		Phase C	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.90
		Minimum	0.83	0.83	0.82	0.82	0.82	0.81	0.81	0.81	0.80	0.80
		Phase A	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.89	0.89
		Phase B	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
		Phase C	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Minimum	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.89	0.89
		Phase A	0.84	0.84	0.83	0.82	0.81	0.81	0.81	0.81	0.81	0.81
		Phase B	0.83	0.83	0.82	0.80	0.80	0.80	0.80	0.79	0.79	0.79
		Phase C	0.94	0.95	0.94	0.93	0.93	0.93	0.93	0.93	0.93	0.93
		Minimum	0.83	0.83	0.82	0.80	0.80	0.80	0.80	0.79	0.79	0.79
		Phase A	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.93	0.93	0.93
		Phase B	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
		Phase C	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90
		Minimum	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
		Phase A	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
		Phase B	0.92	0.92	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90
		Phase C	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
		Minimum	0.92	0.92	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90
		Phase A	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
		Phase B	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Phase C	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Minimum	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Phase A	0.94	0.94	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
		Phase B	0.94	0.94	0.94	0.94	0.93	0.93	0.93	0.92	0.92	0.92
		Phase C	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91
		Minimum	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91
		Phase A	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase B	0.93	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90
		Phase C	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98

		Minimum	0.93	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90
		Phase A	0.89	0.89	0.89	0.88	0.87	0.87	0.86	0.86	0.86	0.86
		Phase B	0.95	0.95	0.94	0.94	0.93	0.93	0.93	0.93	0.93	0.93
		Phase C	0.92	0.92	0.91	0.91	0.90	0.90	0.89	0.89	0.89	0.89
		Minimum	0.89	0.89	0.89	0.88	0.87	0.87	0.86	0.86	0.86	0.86
		Phase A	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97
		Phase B	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase C	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.95	0.95
		Minimum	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.95	0.95
		Phase A	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90
		Phase B	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase C	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
		Minimum	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90
		Phase A	0.93	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90
		Phase B	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Phase C	0.94	0.94	0.94	0.94	0.94	0.93	0.93	0.93	0.92	0.92
		Minimum	0.93	0.93	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.90

Table 3-7. Power Quality: Voltage Profile

SUBSTATION	FEEDER	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Electrically Farthest Section
	F1	3.3%	3.2%	3.3%	3.5%	3.6%	3.8%	2.8%	3.0%	3.2%	3.3%	SAF1_123-95
	F2	3.2%	6.0%	6.4%	6.8%	7.2%	7.7%	8.1%	8.6%	9.1%	9.6%	SAF2_186
	F3	1.2%	1.1%	1.2%	1.2%	1.3%	1.4%	1.4%	1.5%	1.5%	1.6%	SAF3_136
	F1	2.4%	2.4%	2.6%	2.5%	2.4%	2.5%	2.4%	2.6%	2.3%	2.4%	SBF1_214
	F2	7.7%	7.6%	7.9%	8.3%	8.6%	8.5%	8.4%	7.2%	7.5%	7.8%	SBF2_165
	F3	1.3%	1.3%	1.3%	1.4%	1.5%	1.6%	1.6%	1.7%	1.8%	1.8%	SBF3_77
	F1	5.9%	5.8%	6.2%	6.0%	6.0%	6.3%	5.2%	5.5%	5.7%	6.0%	SCF1_210

ALICIA SUBSTATION 5MVA	F2	4.6%	4.5%	4.5%	4.4%	4.7%	4.2%	4.4%	4.7%	4.5%	4.5%	SCF2_220-3
	F1	9.0%	8.8%	9.4%	10.0%	1.1%	1.0%	9.8%	1.0%	1.1%	1.0%	SDF1_292
	F2	3.0%	3.0%	2.9%	3.0%	2.9%	3.0%	2.8%	3.0%	2.9%	3.0%	SDF2_121
	F3	5.3%	5.2%	5.5%	5.4%	6.1%	5.9%	6.2%	6.2%	6.0%	6.0%	SDF3_43-111
	F4	0.0%	0.7%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	SDF4_80
	F1	2.8%	2.7%	2.8%	2.8%	2.8%	2.4%	2.5%	2.6%	2.7%	2.8%	SEF1_101
	F2	4.0%	4.0%	4.2%	4.4%	4.6%	4.9%	5.1%	5.3%	5.6%	5.8%	SEF2_159
	F3	3.4%	3.3%	3.5%	3.7%	3.8%	4.0%	4.2%	4.2%	4.2%	4.2%	SEF3_190-47
	F1	1.7%	1.7%	1.7%	1.8%	1.9%	2.0%	2.1%	2.2%	2.3%	2.4%	SFF1_90
	F2	3.58%	3.51%	3.70%	3.89%	4.08%	4.27%	4.47%	4.66%	4.85%	4.91%	SFF2_131
	F3	0.67%	0.65%	0.69%	0.73%	0.77%	0.82%	0.86%	0.90%	0.94%	0.98%	

Table 3-8. Power Quality: Voltage Unbalance

3.4 Safety Analysis

It is also important to conduct Safety Analysis of the distribution system. We conduct safety analysis by calculating the minimum and maximum faults in all nodes with protective devices, and at the farthest node of the feeders. Protective devices must have a minimum 10% margin over the maximum fault current expected at the location of the protective device. Also, protective devices must be able to sense the minimum fault current within the zone of protection of the protective device. In table 3-9 we show the simulated fault current levels in the distribution system and indicate whether protective devices satisfy the minimum required margins.

Substation	Protection Point	Protective Device	Maximum Assymetrical Fault (Amps)	Protective Device Short Circuit Duty	Safety Margin > 110%	Remarks
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	3695	12500	338%	
	Feeder 2	RECLOSER	3930	4000	102%	
	Feeder 3	RECLOSER	3869	3000	78%	
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	5547	12500	225%	
	Feeder 2	RECLOSER	5953	4000	67%	
	Feeder 3	RECLOSER	5518	12500	227%	
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	6469	12500	193%	
	Feeder 2	RECLOSER	6473	12500	193%	
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	7749	12500	161%	
	Feeder 2	RECLOSER	7749	12500	161%	
	Feeder 3	RECLOSER	7776	12500	161%	
	Feeder 4	RECLOSER	7776	12500	161%	
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	12420	12500	101%	
	Feeder 2	RECLOSER	14182	4000	28%	
	Feeder 3	RECLOSER	12420	12500	101%	
	69KV Take off	OCB				
	13.2 KV Take off	RECLOSER				
	Feeder 1	RECLOSER	6060	4000	66%	
	Feeder 2	RECLOSER	6155	12500	203%	
	Feeder 3	RECLOSER	6059	4000	66%	

Table 3-9. Protection Equipment Safety Margins

Substation	Protection Point	Pick up Current Phase-Phase/Phase-Ground TOC	Pick up Current Down Stream	Design Peak Load	Minimum Fault	Remarks
	OCB: 69KV					
	Recloser: 13.2 KV					
	Recloser: Feeder 1	130	None	85	124.4	
	Recloser: Feeder 2	70	None	58	141.7	
	Recloser:Feeder 3	50	None	20	154.4	
	69KV Take off					
	13.2 KV Take off					
	Feeder 1	100	None	38	138.6	
	Feeder 2	70	None	38	160.9	
	Feeder 3	80	None	36	164.2	
	69KV Take off					
	13.2 KV Take off					
	Feeder 1	150	None	90	139.7	
	Feeder 2	130	None	98	139.7	
	69KV Take off					
	13.2 KV Take off					
	Feeder 1	70	None	85	100.7	
	Feeder 2	108	None	92	170.2	
	Feeder 3	70	None	50	163.2	
	Feeder 4	70	None	15	159.0	
	69KV Take off					
	13.2 KV Take off					
	Feeder 1	120	None	58	161.8	
	Feeder 2	70	None	25	168.6	
	Feeder 3	120	None	76	142.0	

Mahayag Substation	69KV Take off					
	13.2 KV Take off					
	Feeder 1	70	None	18	137.5	
	Feeder 2	80	None	30	160.1	
	Feeder 3	70	None	35	139.5	

Table 3-10. Equipment Protection Pickup Setting

3.5 Efficiency Analysis

Table 3-11 summarizes the total system loss of the system for the years 2016-2025. The segregated system loss per component in the system allows us to target reduction of system losses and choose projects that will help reduce it to the standard set forth by ERC (See Annex B).

FEEDER	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	8.04%	7.56%	7.89%	8.22%	8.57%	8.11%	8.38%	8.64%	8.91%	9.18%
SAF2	8.75%	8.13%	8.28%	8.45%	8.62%	8.81%	9.00%	9.20%	9.40%	9.62%
SAF3	12.98%	12.35%	12.09%	11.86%	11.68%	11.53%	11.40%	11.31%	11.24%	11.18%
SBF1	7.98%	8.14%	8.06%	7.98%	7.89%	7.84%	7.81%	7.80%	7.80%	7.82%
SBF2	7.82%	7.41%	7.56%	7.73%	7.91%	8.10%	8.30%	8.52%	8.74%	8.97%
SBF3	7.08%	6.76%	6.87%	6.99%	7.12%	7.26%	7.42%	7.57%	7.74%	7.92%
SCF1	7.73%	6.95%	6.84%	6.75%	6.68%	6.63%	6.60%	6.57%	6.55%	6.55%
SCF2	9.29%	8.69%	8.77%	8.88%	9.02%	9.17%	9.35%	9.56%	9.78%	10.03%
SDF1	12.56%	11.79%	12.08%	12.39%	12.72%	13.07%	13.43%	13.80%	14.19%	14.58%
SDF2	8.31%	7.69%	7.91%	8.13%	8.35%	8.58%	8.81%	9.03%	9.35%	9.70%
SDF3	7.85%	7.17%	7.14%	7.61%	7.13%	7.15%	7.18%	7.27%	7.39%	7.53%
SDF4	17.87%	17.09%	13.72%	13.41%	13.14%	12.92%	12.72%	12.56%	12.42%	12.30%
SEF1	14.96%	13.77%	14.14%	14.56%	15.03%	15.61%	16.26%	17.00%	17.81%	18.72%
SEF2	9.78%	9.11%	9.03%	8.99%	8.98%	9.00%	9.05%	9.11%	9.19%	9.29%
SEF3	7.59%	6.90%	6.93%	6.97%	7.03%	7.10%	7.17%	0.78%	0.74%	0.71%

SFF1	10.26%	9.72%	9.66%	9.64%	9.65%	9.67%	9.72%	9.79%	9.88%	9.98%
SFF2	9.78%	9.23%	9.38%	9.55%	9.74%	9.95%	10.18%	10.42%	10.16%	10.96%
SFF3	11.45%	10.42%	10.12%	9.86%	9.65%	9.47%	9.33%	9.21%	9.11%	9.03%
TOTAL	**9.13%**	**8.51%**	**8.56%**	**8.70%**	**8.79%**	**8.85%**	**8.99%**	**8.53%**	**8.68%**	**8.87%**

Table 3-11. System Loss

3.6 Summary of Performance Assessment of the Distribution System

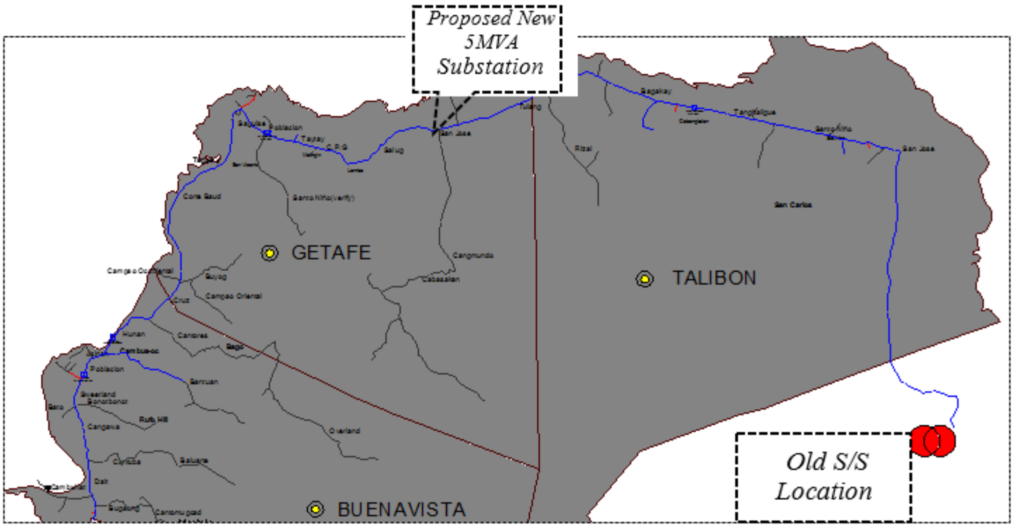
No.	Problem Description	Problem Type
1	Some of the existing feeder protection are identified using single phase recloser that may result to possible damages to the large load/3 phase motor in the distribution system due to unbalance supply during a single phase fault interruption.	Safety
2	A number of existing line in the distribution system are identified unsafe due to its sub-standard, deterioration and low clearances which is subject for rehabilitation and replacement.	Safety
3	In capacity analysis simulation Alicia Substation indicate that its current demand exceed the 70% loading percentage and not feasible to accommodate the demand growth of the substation. *But, it will be corrected for a load transfer to Mahayag Substation upon the completion of uprating of Mahayag Substation as per approved in the previous CAPEX.*	Capacity
4	Distribution Transformer capacity deficiency to address the additional demand of increasing number of consumer as per forecasted.	Capacity
5	Deficiency of Kilowatt-hour meter and service line equipment to provide standard connection for the additional consumer as per forecasted.	Capacity
6	The Mahayag Substation Feeder 3 identified that, existing line configuration cannot provide a consumer with a 3 Phase line requirement which will located in center of the town, where, 3Phase distribution line are only 19% of the total backbone line kilometers or the end point of 3phase line have an estimate of 13kilometer away from the center of the town where most of the projected 3Phase load located.	Capacity
7	The simulation result of Trinidad Feeder 1 and 2 (SDF1 & SDF2) using the Distribution System Applied software *(DSAS-DSL,* indicate that the Voltage Profile at the electrically farthest point of the distribution line did not meet the allowable $\pm$ 10% voltage range criterion of the nominal voltage and the maximum percentage of voltage unbalance, It was also supported in Economic load reach that the average existing size of wire backbone conductor and kilometers of line are not economically feasible.	Power Quality

8	The simulation result of Alicia Substation Feeder 1 (SCF1)using the Distribution System Applied software *(DSAS-DSL,* indicate that the Voltage Profile at the electrically farthest point of the distribution system did not meet the allowable ± 10% voltage range criterion of the nominal voltage *But, it will be corrected for a load transfer to Mahayag Substation upon the completion of uprating of Mahayag Substation as per approved in the previous CAPEX*.	Power Quality
9	The simulation result of Garcia Substation Feeder 1 (SAF1)using the Distribution System Applied software *(DSAS-DSL,* indicate that the Voltage Profile at the electrically farthest point of the distribution system did not meet the allowable ± 10% voltage range criterion of the nominal voltage *But, it will be corrected for a load transfer to New Substation upon the completion of additional Substation project as per approved in the previous CAPEX.*	Power Quality
10	In reference of the reports of area supervisor and corroborate the image capture through google earth, some part of Mahayag Substation Feeder 3 (SFF3) distribution line are not accessible for a maintenance service vehicle which can delay the restoration period of the distribution power outage	Reliability
11	Replacement of Distribution line equipment (i.e. inaccuracy and defective kilowatt-hour meter and transformer unit) to optimized its inherent kWh loss.	System Loss
12	Lack of tools, equipment and gadget for the daily operation of BOHECO II workforce to achieve the objectives of good service towards consumer.	Non-Network

Chapter 4: SUBSTRANMISSION AND SUBSTATION PROJECTS

4.1 N-Project 1: Additional Substation Project

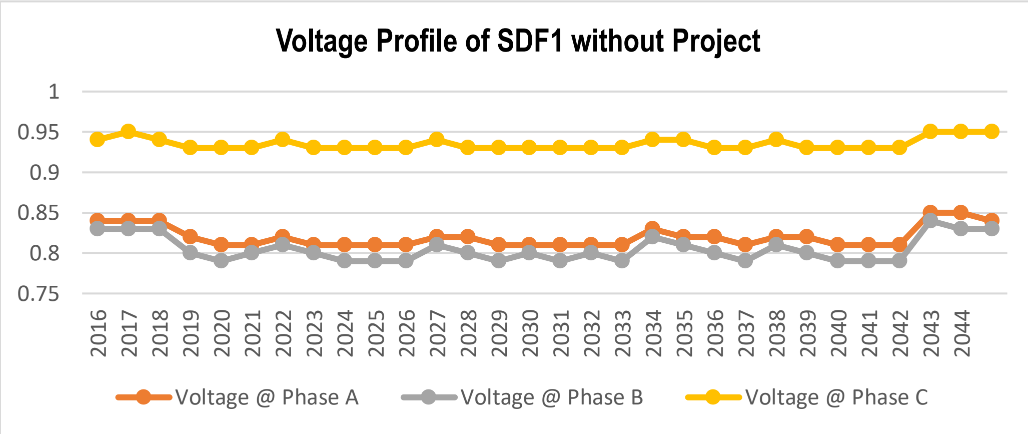
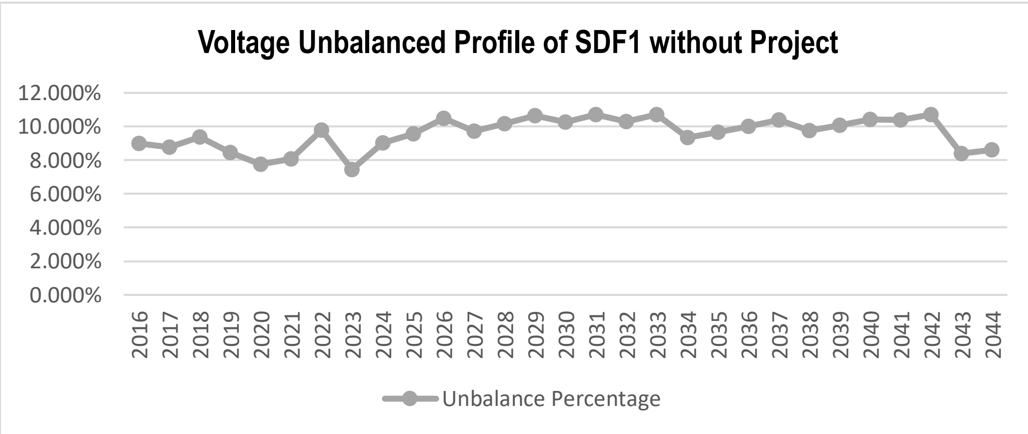
A. NETWORK CAPEX					
Project Code	NP-01	**Project Type**	Power Quality	**Priority Rank**	1st Priority
Project Category	Additional Substation				
Project Title	Additional 5MVA Substation at San Jose, Getafe + 22.71km 69KV Line and Lot Acquisition				
Project Cost	**Php 140,931,528.00**				
Project Duration	2017-2018				
Project Description	This project include: 1. Installation of 5MVA Power Substation at San Jose, Getafe. 2. Construction of 22.71 km of 69KV sub transmission Trinidad Substation to Proposed new substation. 3. Procurement of Site				



<table>
<tr>
<td>Project Justification</td>
<td>
Simulation result of the voltage profile of distribution system in previous chapter indicate that, Trinidad substation Feeder 1 (SDF1) voltage profile did not meet the standard ±10% of nominal voltage as prescribes in Philippine Distribution Code. Trinidad Substation Feeder 1 (SDF1) with a total 3 Phase distribution line of 44km of ACSR 2/0 wire size and its current loading does not adhere to the economic load reach (based on line sizing economics).
The installation of new substation will address the power quality problem of the said feeder and provide reliability of supply in the area in case the adjacent substation conducts preventive maintenance or vise-versa.
To address of this quantified problem, Planning personnel generated a number of project ideas to determine which is technically feasibility as table below shows.
<table>
<tr><th colspan="2">Project Ideas (Solutions)</th><th>Remarks</th></tr>
<tr><td>Alternative 1</td><td>DO NOTHING</td><td>Not feasible</td></tr>
<tr><td>Alternative 2</td><td>Additional 5MVA Substation at Poblacion,Getafe + 29.21km 69KV Line and Lot Acquisition</td><td>Feasible</td></tr>
<tr><td>Alternative 3</td><td>Additional 5MVA Substation at San Jose,Talibon + 11.64km 69KV Line and Lot Acquisition</td><td>Not feasible</td></tr>
<tr><td>Alternative 4</td><td>Additional 5MVA Substation at San Jose,Getafe + 22.71km 69KV Line and Lot Acquisition</td><td>Feasible</td></tr>
<tr><td>Alternative 5</td><td>Additional 5MVA Substation at San Jose,Talibon + 11.64km 69KV Line and Lot Acquisition+18.08km Double Circuit Line</td><td>Not Feasible</td></tr>
</table>
</td>
</tr>
</table>

Technically Feasible Alternatives		
Problem Description	Voltage Profile Problem of Trinidad Substation Feeder 1	
Project Ideas (Solutions)		**Classification**
Alternative 2	Additional 5MVA Substation at Poblacion, Getafe + 29.21km 69KV Line and Lot Acquisition	Stand Alone

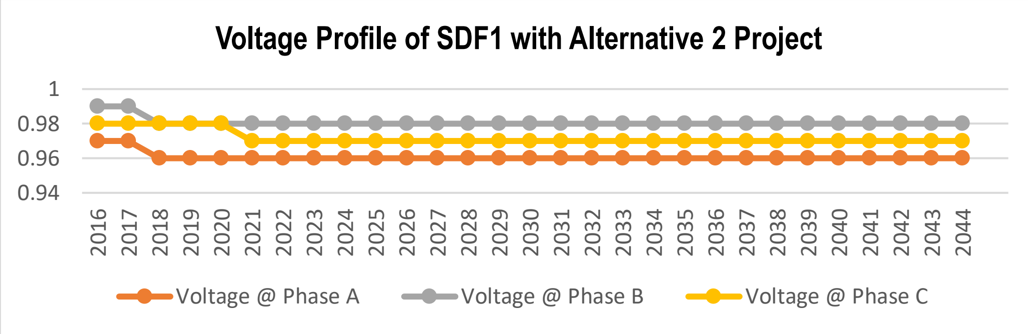
Alternative 4	Additional 5MVA Substation at San Jose, Getafe + 22.71km 69KV Line and Lot Acquisition	Stand Alone

Summary of Technically Feasible Project Alternatives Analysis	
Problem Description	Additional 5MVA Substation at San Jose,Getafe + 22.71km 69KV Line and Lot Acquisition
DO NOTHING	<u>*System Performance without Project:*</u> Voltage Profile:  Unbalance Voltage Percentage Profile: 
Alternative 2	

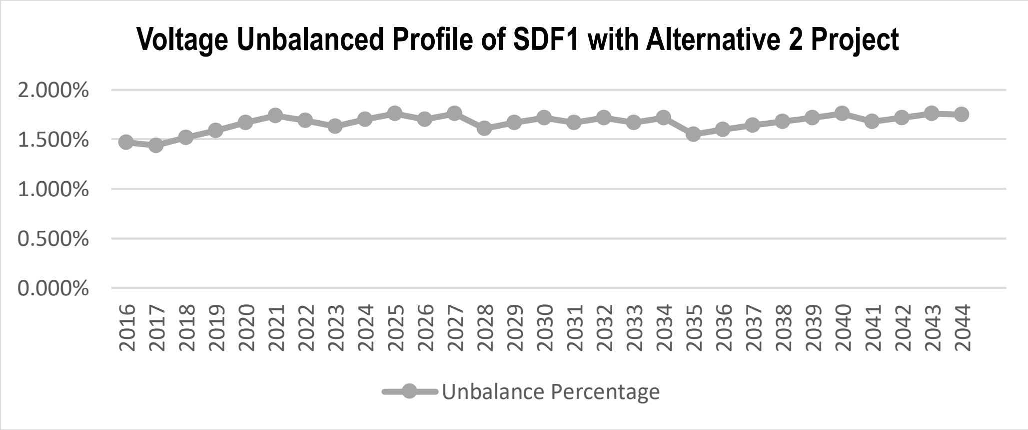
Project Description: Additional 5MVA Substation at Poblacion,Getafe + 29.21km 69KV Line and Lot Acquisition

System Performance with alternative 2 Project:

Voltage Profile:



Unbalance Voltage Profile:



Technical Loss reduction:

YEAR	Do Nothing	Alternative 2 Project	% Reduction	Energy not Consume Cost (PHP)
2019	900,001	450,994	49.890%	2,267,482
2020	962,148	482,529	49.849%	2,422,072
2021	1,026,603	515,308	49.805%	2,582,041
2022	1,093,277	549,307	49.756%	2,747,052

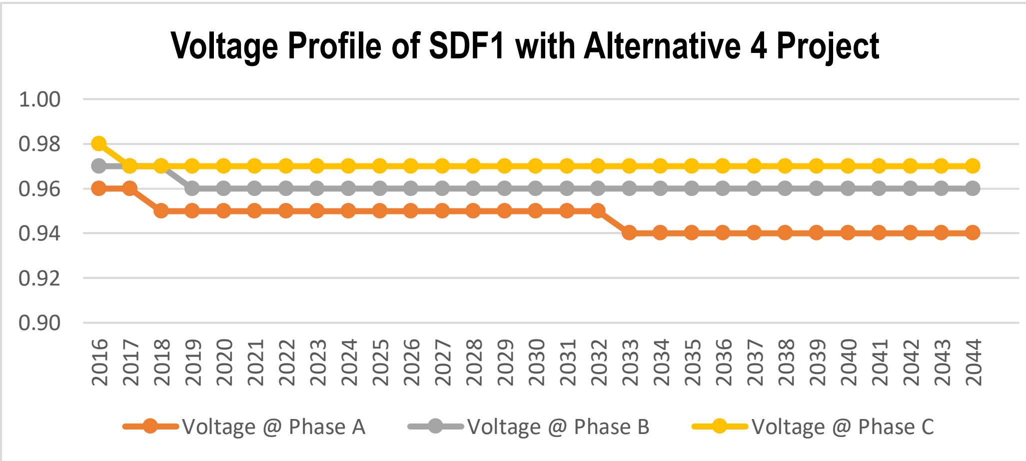
2023	1,162,085	584,502	49.702%	2,916,792
2024	1,232,947	620,873	49.643%	3,090,972
2025	1,305,789	658,398	49.579%	3,269,323
2026	1,380,540	697,056	49.508%	3,451,595
2027	1,457,136	736,827	49.433%	3,637,560
2028	1,550,526	777,693	49.843%	3,902,805

Alternative 4

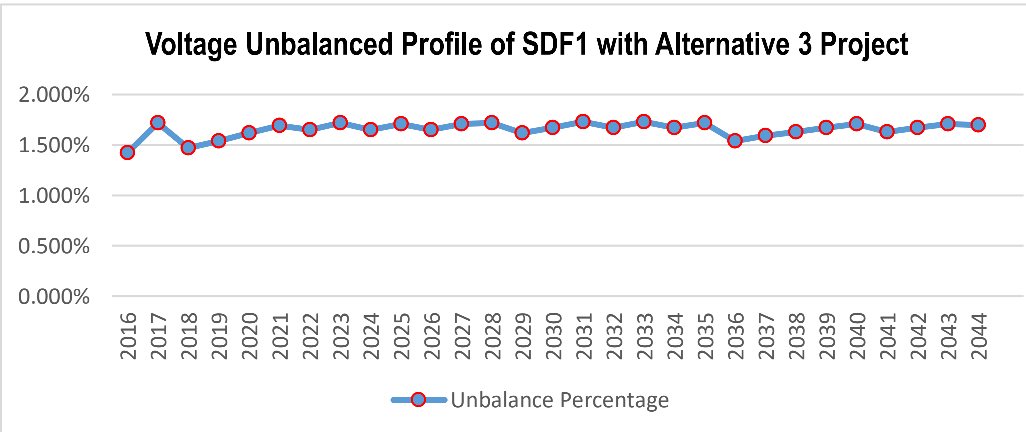
Project Description: Additional 5MVA Substation at San Jose,Getafe + 22.71km 69KV Line and Lot Acquisition

System Performance with alternative 4 Project:

Voltage Profile:



Unbalance Voltage Profile:



	Technical Loss reduction:

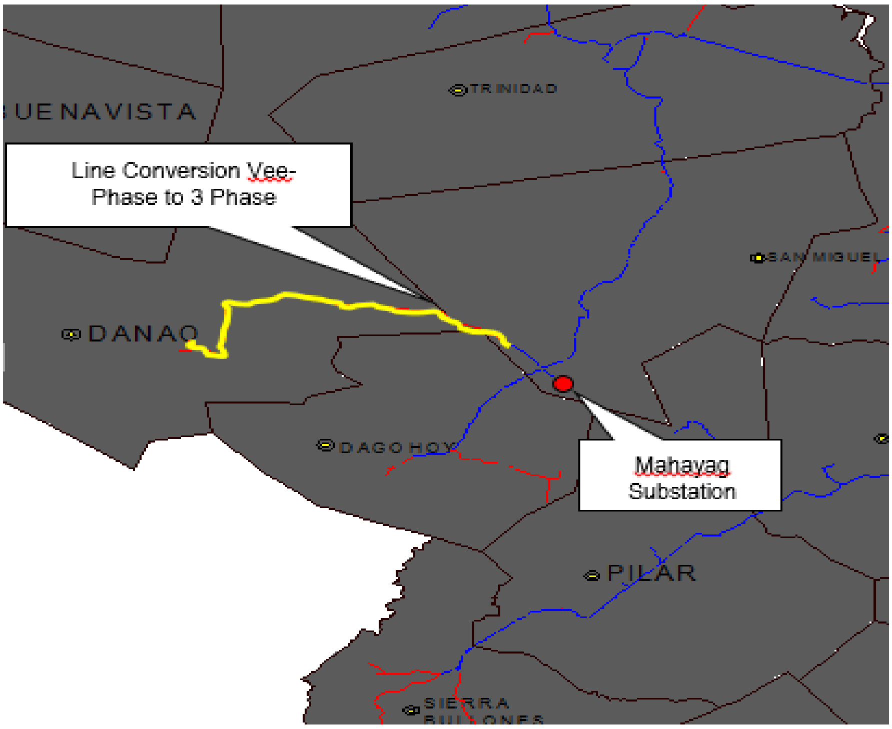
YEAR	Do Nothing	Alternative 2 Project	% Reduction	Energy not Consume Cost (PHP)
2019	900,001	489,923	45.564%	-
2020	962,148	524,451	45.492%	2,070,891
2021	1,026,603	560,352	45.417%	2,210,367
2022	1,093,277	597,597	45.339%	2,354,568
2023	1,162,085	636,159	45.257%	2,503,184
2024	1,232,947	676,010	45.171%	2,655,927
2025	1,305,789	717,124	45.081%	2,812,533
2026	1,380,540	759,476	44.987%	2,972,757
2027	1,457,136	803,042	44.889%	3,136,372
2028	1,550,526	847,799	45.322%	3,303,173

Summary of Economic/Financial Evaluation of Technically Feasible Projects			
Project that "Must Meet Criteria"			
Problem Description	Power Quality Problem in Trinidad Substation Feeder 1		
Project Alternative	Project Description	Present Worth	REMARKS
Alternative 2	Additional 5MVA Substation at Poblacion,Getafe + 29.21km 69KV Line and Lot Acquisition	**255,153,949**	
Alternative 4	Additional 5MVA Substation at San Jose,Getafe + 22.71km 69KV Line and Lot Acquisition	**227,387,440**	Least Cost

See Annex C.

Chapter 5: PRIMARY DISTRIBUTION SYSTEM PROJECT

5.1 N-Project 2: Line Conversion of Vee-Phase to 3 Phase line

B. NETWORK PROJECT					
Project Code	NP-02	Project Type	Consumer Requirement	Priority Rank	1st Priority
Project Category	Primary Distribution Line				
Project Title	Line conversion of 13.423 kilometers of Vee-Phase to 3 Phase line.				
Project Cost	Php 4,636,858.59				
Project Duration	2017-2018				
Project Description	This Project will implement the conversion of Vee-Phase to 3 Phase lines. 				

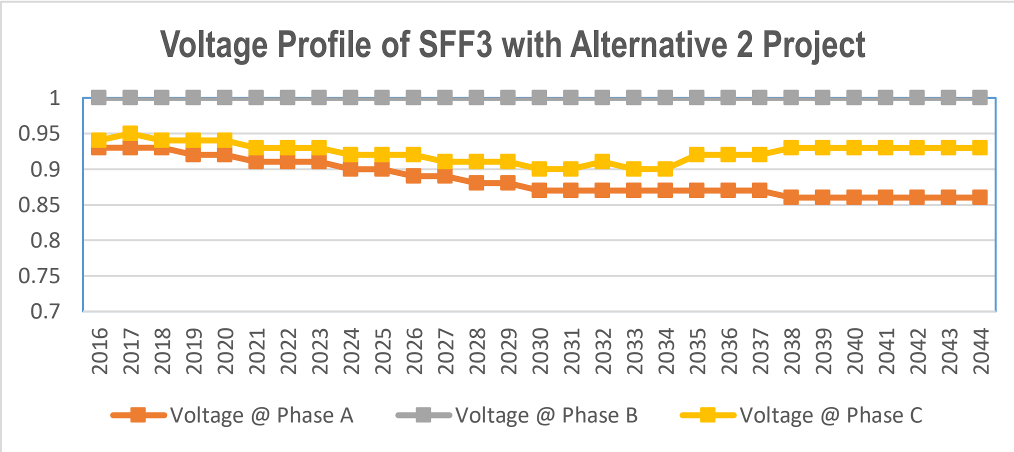
Project Justification	For the Mahayag substation Feeder 3 “SFF3”, only 14% of the total backbone line is three-phase. Line conversion from Vee-phase to three-phase is needed to improve voltage profile and comply with three-phase requirements of new consumers.

KILOMETERS OF LINE		
3 Phase	2.12942	km
Vee phase	13.795	km
Single Phase	53.533	km
Open Secondary	20.053	km
KILOMETER OF LINE		
Residential	2628	unit
Low Voltage	237	unit
High Voltage	0	unit
KILOMETER OF LINE		
Distribution Transformer	48	unit
Private Transformer	29	unit
KILOMETER OF LINE		
Primary Line Pole	634	unit
Secondary Line Pole	290	unit

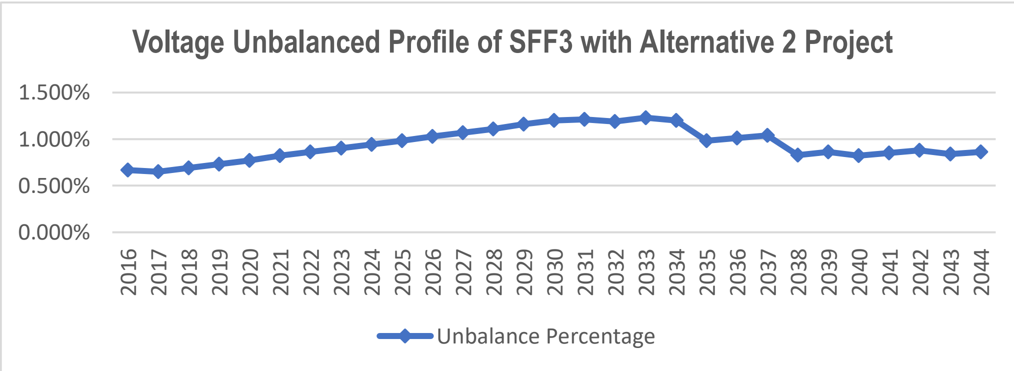
Technical Summary

<u>Project Description:</u> Distribution Line Conversion from Vee Phase to 3 Phase Line

Voltage Profile:



Unbalance Voltage:



System Loss Reduction:

YEAR	Do Nothing	Alternative 2 Project	% Reduction	Energy not Consume Cost (PHP)
2019	135,777	118,539	12.696%	87,056
2020	146,329	127,335	12.980%	95,920
2021	157,397	136,558	13.240%	105,237

	2022	168,981	146,207	13.477%	115,009
	2023	181,083	156,283	13.695%	125,237
	2024	193,705	166,789	13.895%	135,925
	2025	206,849	177,725	14.080%	147,075
	2026	220,518	189,093	14.250%	158,692
	2027	234,715	200,897	14.408%	170,780
	2028	249,446	213,139	14.555%	183,346

See Annex C

5.2 N-Project 3: Upgrading of Substation Protection Equipment

C. NETWORK CAPEX					
Project Code	NP-03	**Project Type**	Reliability	**Priority Rank**	1st Priority
Project Category	Substation Protection Upgrading				
Project Title	Replacement of the Feeder's Single Phase Recloser with 3-Phase Recloser				
Project Cost	**Php 17,177,923.06**				
Project Duration	2017-2018				

Project Description	As shown in table below , this project will replace all single phase reclosers.

Substation Name	Feeder Name	Protection Device	Protection Type	Qty	Remarks
	SAF1	Recloser	3 Phase	1	
	SAF2	Recloser	Single Phase	3	
	SAF3	Recloser	Single Phase	3	
	SBF1	Recloser	3 Phase	1	
	SBF2	Recloser	3 Phase	1	
	SBF3	Recloser	3 Phase	1	
	SCF1	Recloser	3 Phase	1	
	SCF2	Recloser	3 Phase	1	
	SDF1	Recloser	3 Phase	1	
	SDF2	Recloser	Single Phase	3	
	SDF3	Recloser	Single Phase	3	
	SDF4	Recloser	Single Phase	3	
	SEF1	Recloser	3 Phase	1	
	SEF2	Recloser	Single Phase	3	
	SEF3	Recloser	3 Phase	1	
	SFF1	Recloser	3 Phase	1	
	SFF2	Recloser	Single Phase	3	
	SFF3	Recloser	3 Phase	1	

Project Justification	For feeders supplying three-phase loads, the protection equipment must open all its three-phase contacts to prevent the damage to three-phase motors of consumers during unbalanced fault conditions.

See Annex C

Chapter 6: SECONDARY DISTRIBUTION PROJECT

6.1 NN-Project 1: Add-ons for New Consumer

NON-NETWORK CAPEX					
Project Code	NNP-01	**Project Type**	Non-Network Asset	**Priority Rank**	1st Priority
Project Category	Add-ons CAPEX				
Project Title	Acquisition of Distribution Transformers, Service Drops and Metering Equipment for New Consumer Connections (Magna Carta)				
Project Cost	**Php 45,864,541.82**				

Project	2017	2018	TOTAL
Distribution Transformer			
Transformer Unit	4,927,350.05	5,075,170.55	10,002,520.60
Accessories	804,358.58	828,489.33	1,632,847.91
KWH Meter			
KWH Meter Unit	6,454,091	6,519,646	12,973,737.61
Accessories	3,811,512	3,850,049	7,661,560.62

	<table><tr><td colspan="4">**Service Drop Wire**</td></tr><tr><td>AL # 6 SDW, 30 mts /Consumer</td><td>3,227,194.15</td><td>3,259,823.19</td><td>6,487,017.33</td></tr><tr><td>Accessories</td><td>3,535,555.48</td><td>3,571,302.26</td><td>7,106,857.74</td></tr><tr><td>**TOTAL**</td><td>**22,760,061.37**</td><td>**23,104,480.45**</td><td>**45,864,541.82**</td></tr></table>
Project Duration	2017-2018
Project Description	The project will cover the following: 1. Acquisition of distribution transformers for additional/new Consumers 2. Acquisition of KWHR meter and Service Drop Wire for new consumers
Project Justification	This project will address the requirement for additional connection equipment for future forecasted residential consumers. This is to ensure that new consumers will be readily connected and for theEC to comply with the Magna Carta for Residential Consumers. ***<u>Project Impact to KWHR Loss:</u>*** Table below shows the reduction of inherent loss between SILICON and AMORPHOUS core transformer. <table><tr><td rowspan="2">**KVA**</td><td colspan="3">**SILICON STEEL LOSSES** (100% Loading)</td><td colspan="3">**AMORPHOUS METAL LOSSES** (100% Loading)</td><td rowspan="2">Coreloss Reduction Percentage</td></tr><tr><td>Core loss</td><td>Copper Loss</td><td>Total</td><td>Core loss</td><td>Copper Loss</td><td>Total</td></tr><tr><td>3</td><td>9</td><td>45</td><td>54</td><td>8</td><td>45</td><td>53</td><td>11%</td></tr><tr><td>5</td><td>19</td><td>75</td><td>94</td><td>8</td><td>75</td><td>83</td><td>58%</td></tr><tr><td>10</td><td>36</td><td>120</td><td>156</td><td>12</td><td>120</td><td>132</td><td>67%</td></tr><tr><td>15</td><td>50</td><td>195</td><td>245</td><td>15</td><td>195</td><td>210</td><td>70%</td></tr><tr><td>25</td><td>80</td><td>290</td><td>370</td><td>18</td><td>290</td><td>308</td><td>78%</td></tr><tr><td>37.5</td><td>105</td><td>360</td><td>465</td><td>30</td><td>360</td><td>390</td><td>71%</td></tr></table>

50	135	500	635	32	500	532	76%
75	190	650	840	45	650	695	76%
100	210	850	1060	50	850	900	76%
167	350	1410	1760	65	1410	1475	81%

Table below shows the reduction of inherent loss between MECHANICAL and ELECTRONICS kwhr meter.

Type of Meter	Qty.	Average Inherent Loss	Annual Loss (KWHR)	Energy Cost (PHP)
Mechanical	1	0.86	7.53	38.04
Electronics	1	0.1971	1.73	8.72
Saving			**5.81**	**29.33**
Loss Reduction Percentage			**77%**	

	QTY/Number of Customer		Energy Cost Saving	
	2017	2018	2017	2018
Mechanical	4,609	4,520	34,722.36	34,051.87
Electronics	4,609	4,520	7,957.88	7,804.21
Energy Save (KWH)			**26,64.48**	**26,247.66**
Cost Save (PHP)			**135,160.63**	**132,550.67**

<u>SYSTEM LOSS CHARGE</u>: Table below shows the benefits of system loss reduction to system loss charge.

System Loss Rate = (TGR + ATR) * U + OSLA

Where, U; Gross up Factor = Systemloss / (1-Actual SystemLoss)

SYSTEM LOSS PERCENTAGE RANGE	SLR no CAP	SLR with CAP	Rate Reduction Percentage to

				Member Consumer
	15%	18%	15%	
	14%	16%	15%	0%
	13%	15%	15%	0%
	12%	14%	14%	1.31%
	11%	12%	12%	1.28%
	10%	11%	11%	1.25%
	9%	10%	10%	1.22%
	8%	9%	9%	1.19%
	7%	8%	8%	1.17%
	6%	6%	6%	1.14%
Annexes	See Annex D			

6.2 NN-Project 2: Distribution Equipment acquisition

NON-NETWORK CAPEX					
Project Code	NP-02	**Project Type**	Non-Network Asset	**Priority Rank**	1st Priority
Project Category	Property/Equipment/Others				
Project Title	Acquisition of Distribution Equipment to maintain the operation and reliability of the distribution system				

Project Cost	Php186,334,407.72

Project	2017	2018	TOTAL
Acquisition of Distribution Transformer			
Transformer Unit	11,219,176.64	11,555,751.93	22,774,928.57
Accessories	1,657,466.16	1,707,190.14	3,364,656.30
Acquisition of KWH Meter			
KWH Meter Unit	7,972,664	8,458,199	16,430,862.21
Accessories	8,100,578	8,561,909	16,662,487.16
Acquisition of Wood Pole for Replacement			
Pole	8,525,445.45	8,763,069.54	17,288,514.99
Accessories	3,601,981.62	3,707,020.72	7,309,002.34
Acquisition of Distribution Line			
3Phase Structure	4,612,410.34	4,750,782.65	9,363,192.98
V Phase Structure	1,327,027.17	1,366,837.99	2,693,865.16
1 Phase Structure	15,722,410.75	10,717,782.58	26,440,193.33
UB Structure	2,957,066.57	1,665,142.27	4,622,208.84
OS Structure	36,716,902.46	22,667,593.38	59,384,495.84
TOTAL	**102,413,128.5**	**83,921,279.20**	**186,334,407.72**

Project Duration	2017-2018
Project Description	The project will cover the following: 1. Acquisition of distribution transformers to ensure availability when upgrading or replacement of transformers for routine preventive maintenance; to maintain its service in accordance to the standard. 2. Acquisition of kWHr meters to replace the mechanical, electronics, damages and upgrade of rating for residential, commercial and industrial consumer 3. Acquisition of Distribution Pole to replace the damages/rotten poles service pole and pole relocation.

	4. Acquisition of Distribution Line is to ensure the construction of Line Extension as per Consumer request and Line Upgrading
Project Justification	Conductor, Poles and Transformers are the basic elements of a distribution system to maintain the service of the BOHECO II to its member consumer ***<u>Project Impact to KWHR Loss:</u>*** Table below shows the reduction of inheret loss between SILICON and AMORPHOUS core transformer.

KVA	**SILICON STEEL LOSSES** (100% Loading)			**AMORPHOUS METAL LOSSES** (100% Loading)			Coreloss Reduction Percentage
	Core loss	Copper Loss	Total	Core loss	Copper Loss	Total	
3	9	45	54	8	45	53	11%
5	19	75	94	8	75	83	58%
10	36	120	156	12	120	132	67%
15	50	195	245	15	195	210	70%
25	80	290	370	18	290	308	78%
37.5	105	360	465	30	360	390	71%
50	135	500	635	32	500	532	76%
75	190	650	840	45	650	695	76%
100	210	850	1060	50	850	900	76%
167	350	1410	1760	65	1410	1475	81%

Table below shows the reduction of inherent loss between MECHANICAL and ELECTRONICS kWhr meter.

Type of Meter	Qty	Average Inherent Loss	Annual Loss (KWHR)	Energy Cost (PHP)
Mechanical	1	0.86	7.53	38.04
Electronics	1	0.1971	1.73	8.72
Saving			**5.81**	**29.33**

	Loss Reduction Percentage | 77%

	QTY/Number of Customer		Energy Cost Saving	
	2017	2018	2017	2018
Mechanical	5,078	5,058	38,255.62	38,104.95
Electronics	5,078	5,058	8,767.65	8,733.12
Energy Save (KWH)			**29,487.97**	**29,371.83**
Cost Save (PHP)			**148,914.23**	**148,327.72**

SYSTEM LOSS CHARGE : Table below shows the benefits of system loss reduction to system loss charge.

System Loss Rate = (TGR + ATR) * U + OSLA

Where, U; Gross up Factor = Systemloss / (1-Actual SystemLoss)

SYSTEM LOSS PERCENTAGE RANGE	SLR no CAP	SLR with CAP	Rate Reduction Percentage to Member Consumer
15%	18%	15%	
14%	16%	15%	0%
13%	15%	15%	0%
12%	14%	14%	1.31%
11%	12%	12%	1.28%
10%	11%	11%	1.25%
9%	10%	10%	1.22%
8%	9%	9%	1.19%
7%	8%	8%	1.17%
6%	6%	6%	1.14%

Annexes See Annex D

Chapter 7: NON-NETWORK ASSETS PROJECT

7.1 NN-Project 3: Tools and Gadget procurement

<table>
<tr><td colspan="6">NON-NETWORK CAPEX</td></tr>
<tr><td>Project Code</td><td>NP-03</td><td>Project Type</td><td>Non-Network Asset</td><td>Priority Rank</td><td>1st Priority</td></tr>
<tr><td>Project Category</td><td colspan="5">Property/Equipment and Measuring Equipment</td></tr>
<tr><td>Project Title</td><td colspan="5">Procurement of Equipment, Tools and Gadgets</td></tr>
<tr><td>Project Cost</td><td colspan="5">PHP17,771,942.18
<table>
<tr><th>Project</th><th>2017</th><th>2018</th><th>TOTAL</th></tr>
<tr><td>Measuring Equipment</td><td>5,351,179.60</td><td>1,538,559.62</td><td>6,889,739.22</td></tr>
<tr><td>Spare Equipment</td><td>5,070,041.10</td><td>-</td><td>5,070,041.10</td></tr>
<tr><td>Tools and Safety Gadget (Distribution Line System)</td><td>1,335,673.10</td><td>1,293,788.77</td><td>2,629,461.87</td></tr>
<tr><td>Tools and Safety Gadget (General Services/Motor Pool)</td><td>3,182,700.00</td><td>-</td><td>3,182,700.00</td></tr>
<tr><td>TOTAL</td><td>14,939,593.80</td><td>2,832,348.38</td><td>17,771,942.18</td></tr>
</table>
</td></tr>
<tr><td>Project Duration</td><td colspan="5">2017-2018</td></tr>
<tr><td>Project Description</td><td colspan="5">The project will cover the following:
1. Acquisition of Measuring Equipment
2. Acquisition of Spare equipment for Substation
3. Acquisition of Tools and safety Gadget
4. Acquisition of tools and equipment of Motor Pool</td></tr>
<tr><td>Project Justification</td><td colspan="5"></td></tr>
</table>

	These tools will boost the efffciency of daily activities/tasks, promote safety of working personnel, and further improve the services of BOHECO II.
ANNEXES	See ANNEX D

7.2 NN Project 4: Buffer Stock Procurement

NON-NETWORK CAPEX					
Project Code	NP-04	Project Type	Non-Network Asset	Priority Rank	1st Priority
Project Category	Property/ Equipment /Others				
Project Title	Procurement of Buffer Stock for Contingency/Emergency				
Project Cost	**Php40,144,142**				
Project Duration	2017				
Project Description	Procurement of Buffer Stock for Distribution System to repair damages due to unpredictable natural disasters that may occur. BOHECO II determines the number of major items like Poles, Conductors, Distribution Transformers, electronic kWh meters and service drop which is equivalent to 20% of the total 3-Phase distribution line length.				
Project Justification	Last October 2013 Bohol was struck by a 7.2 magnitude earthquake and was affected by the wrath of typhoon Yolanda in November of the same year. Even if BOHECO II coverage was not largely affected by that event, BOHECO II still needs to acquire material buffer stock for use during emergencies such as during natural calamities that occur more often nowadays due to climate change. ***<u>PROJECT OBJECTIVES</u>***				

	A. Ensure the availability of materials and equipment B. Establish ample stock of materials and equipment for emergency response C. Assure the buffer stock of materials and equipment are in conformity with build back better scheme D. Build a regional pool of linemen and electricians for emergency power restoration
Annexes	See Annex D

7.3 NN-Project 5: Service Vehicle Procurement

NON-NETWORK CAPEX					
Project Code	NP-05	Project Type	Non-Network Asset	Priority Rank	1st Priority
Project Category	Property/ Equipment /Others				
Project Title	Acquisition of Service Vehicle				
Project Cost	**Php47,223,842**				
Project Duration	2017-2018				
Project Description	Acquisition of Service Vehicles for BOHECO II Operations and Maintenance.				
Project Justification	These vehicles will boost the efficiency of daily activities/tasks, promote safety of working personnel, and further improve the services of BOHECO II to its consumers				
ANNEX	Annex D				

7.4 NN Project 6: Software Applications

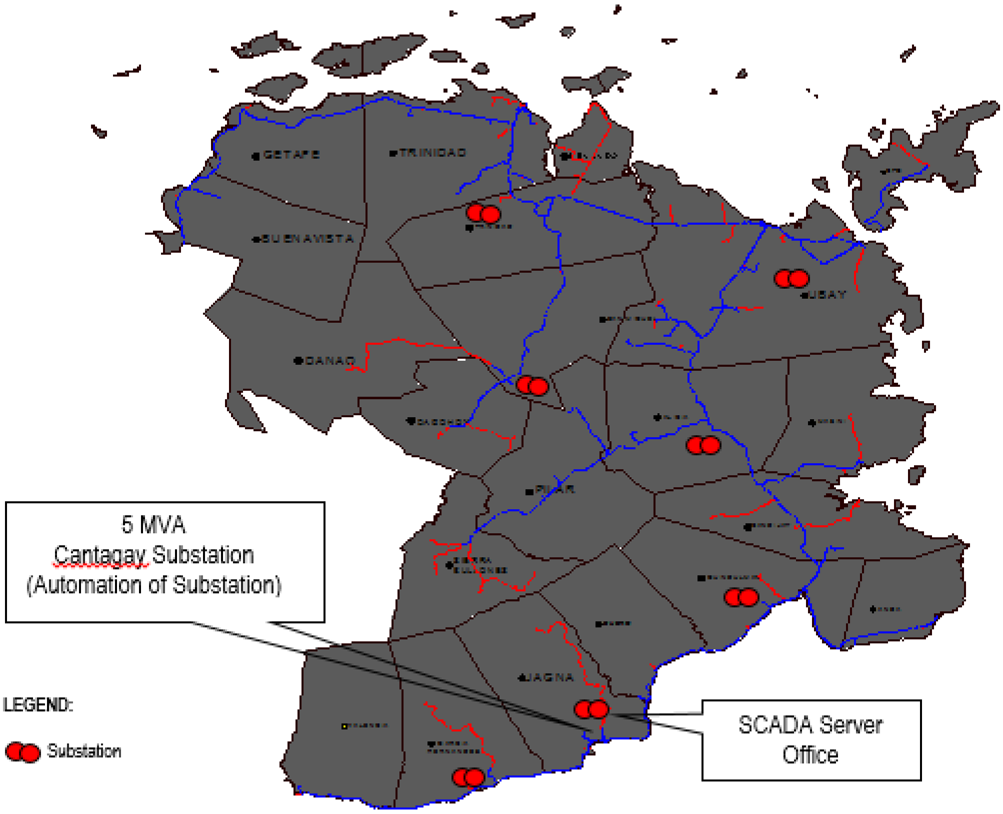
<table>
<tr><td colspan="6">NON - NETWORK CAPEX</td></tr>
<tr><td>Project Code</td><td>NP-06</td><td>Project Type</td><td>Non-Network Asset</td><td>Priority Rank</td><td>1st Priority</td></tr>
<tr><td>Project Category</td><td colspan="5">Property/ Equipment /Others</td></tr>
<tr><td>Project Title</td><td colspan="5">Acquisition and upgrading of Software Applications for Distribution System Planning and Operations</td></tr>
<tr><td>Project Cost</td><td colspan="5">Php12,694,114.92
<table>
<tr><th>Project</th><th>2017</th><th>2018</th><th>TOTAL</th></tr>
<tr><td>Management Information System</td><td>7,585,435.00</td><td>-</td><td>7,585,435.00</td></tr>
<tr><td>Geographical Information System</td><td>-</td><td>1,925,979.92</td><td>1,925,979.92</td></tr>
<tr><td>Software Updates</td><td>3,182,700.00</td><td>-</td><td>3,182,700.00</td></tr>
<tr><td>TOTAL</td><td>10,768,135.00</td><td>1,925,979.92</td><td>12,694,114.92</td></tr>
</table></td></tr>
<tr><td>Project Duration</td><td colspan="5">2017-2018</td></tr>
<tr><td>Project Description</td><td colspan="5">The project will cover the following:
1. Acquisition of Management Information System for Technical Services, Consumer Services and Accounting and Billing
2. Acquisition of Geographical Information System
3. Upgrade of BOHECO II Software for Operations</td></tr>
</table>

<table>
<tr><td>Project Justification</td><td>This project will further improve the planning, operations and maintenance of the distribution system. They will provide us with a clear map and visual that are essential in our planning stages in our distribution system.

<u>ECONOMIC EVALUATION</u>
<table>
<tr><td colspan="2">INVESTMENT COST</td></tr>
<tr><td>Project COST (MIS Cost only)</td><td>7,585,435.00</td></tr>
<tr><td colspan="2">Present Worth of Project Cost</td></tr>
<tr><td>PW Revenue</td><td>7,931,791</td></tr>
<tr><td>PW Expenses</td><td>7,881,612</td></tr>
<tr><td>Benefits/Cost ratio(B/C)</td><td>1.01</td></tr>
<tr><td>Internal Rate Return(IRR)</td><td>6.12%</td></tr>
<tr><td>Net Present Value(NPV)</td><td>50,179</td></tr>
</table></td></tr>
<tr><td>ANNEXES</td><td>See Annex D</td></tr>
</table>

7.5 NN Project 7: Substation Automation

NON-NETWORK CAPEX					
Project Code	NNP-07	**Project Type**	Non-Network Asset	**Priority Rank**	1st Priority
Project Category	Substation Automation (SCADA Project Phase 1)				
Project Title	Substation Automation for Cantagay Substation				
Project Cost	**Php19,608,880.77**				
Project Duration	2017-2018				
Project Description	SCADA or 'Supervisory Control and Data Acquisition' is a hardware and software system that is used to acquire relevant system data from remote devices and provides overall supersory, regulating or automatic controls remotely from a				

	SCADA control center. Data acquired from SCADA systems are useful in optimal planning of the distribution system and efficient and safe operations. SCADA Host platforms also provide functions for graphical displays, alarming, trending and historical storage of data. Upon the operation of proposed substation in Cantagay Substation, BOHECO II plans to implement the first automated substation (Phase 1) project for the implementation of SCADA System. The figure below shows the location of the proposed substation which is approximately 50 meters from the Main Office. 

Project Justification	The implementation of the project is divided into phases, as stated below: *Phase 1: Substation automation of Cantagay Substation* *Phase 2: Substation Automation of 4 substations, including the installation of fiber optic and wireless communications* *Phase 3: Substation automation of the NGCP-owned substation (Garcia and Imelda Substations)* *Phase 4: The Automation of the downstream switches and reclosers in the distribution system* The table below shows the economic evaluation of the Project, monetary value included is the cost of having personnel to tend the substation. The benefits for operational flexibilities were not included in this evaluation (i.e. actual metering data, fault location, etc.)
ANNEX	Annex D

ECONOMIC EVALUATION	
Phase 1 Project	19,608,880.77
Phase 2 Project	52,410,692.38
Total Project Cost	**72,019,573.15**
Present Worth of Project Cost	
PW Revenue	81,103,628
PW Expenses	80,033,852
Benefits/Cost ratio**(B/C)**	1.01
Internal Rate Return**(IRR)**	6.10%
Net Present Value**(NPV)**	1,069,776

The benefit/cost ratio shows that the project is economically feasible.

Chapter 8: SUMMARY OF CAPITAL EXPENDITURE PROJECTS

Pursuant to ERC Resolution No. 26, Series of 2009, known as the “Resolution amending the rules for Approval of Regulated Entities “Capital Expenditure Project” BOHECO II conducted a feasibility study of its Capital Expenditure Project in year 2017 to 2018 shows in Table 2-1.

Count	Project Code	Project Name	NETWORK Project Cost		
			2017	2018	Total
1	NP-01	Additional 5MVA Substation at San Jose,Getafe + 22.71km 69KV Line and Lot Acquisition	94,131,910.01	46,799,617.92	**119,942,232.17**
3	NP-02	Line Conversion from Vee phase to 3 Phase	-	4,636,858.59	**26,113,596.09**
4	NP-03	Upgrading of Substation Protection Equipment	13,978,418.40	3,199,504.66	**16,955,134.06**
		Network Project	108,110,328.4 1	54,635,981.16	162,746,309.57

			NON-NETWORK Project Cost		
			2017	2018	Total

1	NNP-01	Acquisition of Distribution Transformers, Service Drops and Metering Equipment for New Customer Connections	22,760,061.37	23,104,480.45	**45,864,541.82**
2	NNP-02	Requisition of Distribution Transformers, Poles, KWH meter for replacement and Distribution Line Rehabilitation	102,413,128.51	83,921,279.20	**186,334,407.72**
3	NNP-03	Acquisition of Measuring Equipment, Tools and Gadgets	14,939,593.80	2,832,348.38	**17,771,942.18**
4	NNP-04	Buffer Stock	40,144,420.86		**40,144,420.86**
5	NNP-05	Acquisition of Service Vehicles	17,610,940.00	29,612,901.70	**47,223,841.70**
6	NNP-06	Acquisition and upgrading of Software Applications for Distribution	10,768,135.00	1,925,979.92	**12,694,114.92**

		System and Operation			
7	NNP-07	Automation of Substation (SCADA Phase 1 Project)	19,467,525.61	141,355.16	**19,608,880.77**
		Non-Network Project	**228,103,805.15**	**141,538,344.82**	**369,642,149.97**
		GRAND TOTAL	**336,214,133.56**	**196,174,325.98**	**532,388,459.54**

Table 8-1. CAPEX 2017-2018 Summary

Chapter 9: ANNEXES

9.1 ANNEX A: REFERENCE, TOOLS AND ASSUMPTION DETAILS

9.1.1 Reference:

- Distribution Transformer Handbook for Electric Cooperatives
- Conductor table in Distribution Applied Software
- EC-DU Planning Manual August 10, 2009
- Philippines Distribution Code

9.1.2 Tools:

- Distribution System Applied Software-DSL
- Syneergi Electric Software

9.1.3 Forecasting Equations

Model No.	Equation	Remarks	$R^2 > 0.99$	$R^2_{adjusted} > 0.99$	MAPE < = 3%	t - stat > 2 & < -2	P - Value < 0.1
1	a(t) + b	Passed	0.99	0.99	0.01	passed	passed
2	a(t^2) + b(t) + c	Failed	0.99	0.99	0.01	failed	failed
3	a(t^3)+b(t^2)+c(t)+d	Failed	0.99	0.99	0.01	failed	failed
4	a(t^2) + b	Failed	0.95	0.94	0.02	passed	passed
5	a(t^3) + b(t^2) + c	Failed	0.99	0.99	0.01	passed	passed
6	a(t^3) + b	Failed	0.87	0.85	0.04	passed	passed

7	a(t^3) + b(t) + c	Failed	0.99	0.99	0.01	failed	failed
8	a(lnt) + b	Failed	0.91	0.89	0.04	passed	passed
9	a(lnt^2)+b(lnt)+c	Failed	-1.39	-2.58	0.18	failed	failed
10	a(lnt^3) +b(lnt^2) +c(lnt) +d	Failed	-1.35	-3.71	0.18	failed	failed
11	a(lnt^2) + b	Passed	0.99	0.99	0.01	passed	passed
12	a(lnt^3) +b(lnt^2) +c	Failed	-3.83	-6.25	0.28	failed	failed
13	a(lnt^3) + b	Failed	0.91	0.89	0.04	passed	passed
14	a(lnt^3)+b(lnt)+c	Failed	-3.83	-6.25	0.28	failed	failed
15	a(logt) + b	Failed	0.91	0.89	0.04	passed	passed
16	a(logt^2)+b(logt)+c	Failed	-2.64	-4.46	0.22	failed	failed
17	a(logt^3) +b(logt^2) +c(logt) +d	Failed	-2.47	-5.94	0.22	failed	failed
18	a(logt^2) + b	Failed	0.91	0.89	0.04	passed	passed
19	a(logt^3) +b(logt^2) +c	Failed	-13.17	-20.25	0.44	failed	failed
20	a(logt^3) + b	Failed	0.91	0.89	0.04	passed	passed
21	a(logt^3)+b(logt)+c	Failed	-13.17	-20.25	0.44	failed	failed
22	a(logt) +b(t) +c	Failed	0.99	0.99	0.01	failed	failed
23	a(t^2) +b(t) +c(logt) +d	Failed	0.99	0.99	0.01	failed	failed
24	a(t^2) +b(logt) +c	Failed	0.99	0.99	0.01	passed	passed
25	a(t^3)+b(t^2)+c(logt) +d	Failed	0.99	0.99	0.01	failed	failed
26	a(t^3) +b(logt) +c	Failed	0.99	0.98	0.02	passed	passed
27	a(t^3)+b(t) +c(logt) +d	Failed	0.99	0.99	0.01	failed	failed
28	a(t^-1) + b(t) + c	Failed	0.99	0.99	0.01	failed	failed
29	at^-1 +bt^2 +ct +d	Failed	0.99	0.99	0.01	failed	failed
30	a(t^-1) +b (t^2) +c	Failed	0.99	0.98	0.02	passed	passed
31	a(t^-1) +b(t^3) +c(t^2) +d	Failed	0.99	0.98	0.01	failed	failed
32	a(t^-1) +b (t^3) +c	Failed	0.97	0.96	0.02	passed	passed
33	a(t^-1) +b(t^3) +c(t) +d	Failed	0.99	0.99	0.01	failed	failed

9.1.4 Parameters

Description	Value	Unit	Remarks
Interest Rate (i)	6	%	As reference of
Escalation/Inflation Rate (a)	3	%	Inflation rate of Materials cost are based in 2015 price index
Load Growth rate (g)	4	%	BOHECO II Average historical demand growth for year 2009-2015
Annual O&M Cost and Taxes	3	%	Based on BOHECO II 2015 annual expense of
Power Factor (PF)	0.90		Power Factor
Load Factor (LF)	0.58		Ratio of average demand in a year & Peak Demand
Loss Factor (LSF)	0.41		The ratio of average annual load loss to the load loss that occurs at the peak load
Peak Loss Responsibility Factor (RF)	0.34		The ratio of average annual load loss to the load loss that occurs at the peak load
Energy Charge (CEC)	5.05	PhP/kWh	Equal to average Generation charge of BOHECO II
Demand Charge (CDC)	247.40	PhP/kW	Equal to average Transmission charge of BOHECO II
Electricity Cost (DSM)	2.31	Php/kWh	Equal to Distribution Supply and Metering Charge
Voltage (LL)	13.20	kV	Line to Line Voltage in kilo-Volts
Voltage (LN)	7.62	kV	Line o Ground Voltage in kilo-Volts
% VD Criteria	7.5	%	Voltage Drop criterion instead of $\pm$10%
No. of Periods (n)	30	Years	Planning period is in accordance with material or equipment economic life as per *ERC Resolution No. 43 series of 2006, Materials Lifetime.*
AF (i)	13.76		Annuity Factor with interest rate
AF (i,a)	19.25		Annuity Factor with interest rate and escalation rate
AF (i,a,g)	63.75		Annuity Factor with interest rate and escalation rate
Contingency Loading	90	%	Preferred contingency loading percentage of a conductor

9.1.5 KILOMETER OF LINE COSTING:

Distribution Line Cost per kilometer are vary in size of conductor, Pole top accessories as per type of Line, Distribution Pole, Grounding assembly and Pole Support/anchor assembly. Table below are the distribution costing in parameters.

	SINGLE PHASE LINE						
	4	2	1/0	2/0	3/0	4/0	336400
Primary Conductor	20,700.00	25,300.00	39,100.00	47,150.00	50,600.00	74,750.00	124,200.00
Neutral Conductor	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00
Primary Accessories	19,976.74	19,976.74	20,777.11	22,377.85	24,864.98	24,864.98	24,864.98
Pole	168,000.00	168,000.00	183,750.00	213,500.00	227,500.00	227,500.00	227,500.00
Grounding	2,638.83	2,638.83	2,638.83	1,979.12	1,979.12	1,979.12	1,979.12
Support/Banting	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36
Initial Cost	268,929.92	273,529.92	303,880.29	342,621.33	362,558.45	386,708.45	436,158.45
Labor Cost (30 % TMC)	80,678.98	82,058.98	91,164.09	102,786.40	108,767.54	116,012.54	130,847.54
Contingency (5%TMC)	13,446.50	13,676.50	15,194.01	17,131.07	18,127.92	19,335.42	21,807.92
Freight % Handling (5% TMC)	13,446.50	13,676.50	15,194.01	17,131.07	18,127.92	19,335.42	21,807.92
TOTAL	376,501.89	382,941.89	425,432.41	479,669.86	507,581.83	541,391.83	610,621.83

	TWO PHASE LINE COST						
	4	2	1/0	2/0	3/0	4/0	336400
Primary Conductor	41,400.00	50,600.00	78,200.00	94,300.00	101,200.00	149,500.00	248,400.00
Neutral Conductor	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00
Primary Accessories	66,389.54	66,389.54	70,705.96	79,338.80	87,149.49	87,149.49	87,149.49
Pole	168,000.00	168,000.00	183,750.00	213,500.00	227,500.00	227,500.00	227,500.00
Grounding	2,638.83	2,638.83	2,638.83	1,979.12	1,979.12	1,979.12	1,979.12
Support/Banting	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36
Initial Cost	336,042.72	345,242.72	392,909.14	446,732.28	475,442.96	523,742.96	622,642.96
Labor Cost (30 % TMC)	100,812.82	103,572.82	117,872.74	134,019.68	142,632.89	157,122.89	186,792.89
Contingency (5%TMC)	16,802.14	17,262.14	19,645.46	22,336.61	23,772.15	26,187.15	31,132.15
Freight % Handling (5% TMC)	16,802.14	17,262.14	19,645.46	22,336.61	23,772.15	26,187.15	31,132.15
TOTAL	470,459.81	483,339.81	550,072.80	625,425.19	665,620.15	733,240.15	871,700.15

	THREE PHASE LINE COST						
	4	2	1/0	2/0	3/0	4/0	336400
Primary Conductor	62,100.00	75,900.00	117,300.00	141,450.00	151,800.00	224,250.00	372,600.00

Neutral Conductor	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00
Primary Accessories	88,239.49	88,239.49	93,170.53	103,032.61	110,872.32	110,872.32	110,872.32
Pole	168,000.00	168,000.00	183,750.00	213,500.00	227,500.00	227,500.00	227,500.00
Grounding	2,638.83	2,638.83	2,638.83	1,979.12	1,979.12	1,979.12	1,979.12
Support/Banting	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36
Initial Cost	378,592.67	392,392.67	454,473.71	517,576.09	549,765.80	622,215.80	770,565.80
Labor Cost (30 % TMC)	113,577.80	117,717.80	136,342.11	155,272.83	164,929.74	186,664.74	231,169.74
Contingency (5%TMC)	18,929.63	19,619.63	22,723.69	25,878.80	27,488.29	31,110.79	38,528.29
Freight % Handling (5% TMC)	18,929.63	19,619.63	22,723.69	25,878.80	27,488.29	31,110.79	38,528.29
TOTAL	530,029.74	549,349.74	636,263.19	724,606.52	769,672.11	871,102.11	1,078,792.11

	SECONDARY LINE COST						
	4	2	1/0	2/0	3/0	4/0	336400
Secondary Conductor	20,700.00	25,300.00	39,100.00	47,150.00	50,600.00	74,750.00	124,200.00
Neutral Conductor	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00
Secondary Accessories	6,161.21	6,161.21	6,548.79	7,323.95	8,498.10	8,498.10	8,498.10
Pole	168,000.00	168,000.00	183,750.00	213,500.00	227,500.00	227,500.00	227,500.00
Grounding	2,638.83	2,638.83	2,638.83	1,979.12	1,979.12	1,979.12	1,979.12
Support/Banting	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36	18,514.36
Initial Cost	255,114.39	259,714.39	289,651.97	327,567.43	346,191.58	370,341.58	419,791.58
Labor Cost (30 % TMC)	76,534.32	77,914.32	86,895.59	98,270.23	103,857.47	111,102.47	125,937.47
Contingency (5%TMC)	12,755.72	12,985.72	14,482.60	16,378.37	17,309.58	18,517.08	20,989.58
Freight % Handling (5% TMC)	12,755.72	12,985.72	14,482.60	16,378.37	17,309.58	18,517.08	20,989.58
TOTAL	357,160.15	363,600.15	405,512.76	458,594.40	484,668.21	518,478.21	587,708.21

	UNDERBUILT SECONDARY LINE COST						
	4	2	1/0	2/0	3/0	4/0	336400
Secondary Conductor	20,700.00	25,300.00	39,100.00	47,150.00	50,600.00	74,750.00	124,200.00
Neutral Conductor	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00	39,100.00
SecondaryAccessories	5,574.14	5,574.14	5,961.72	6,736.88	7,323.95	7,323.95	7,323.95
Initial Cost	65,374.14	69,974.14	84,161.72	92,986.88	97,023.95	121,173.95	170,623.95
Labor Cost (30 % TMC)	19,612.24	20,992.24	25,248.52	27,896.06	29,107.19	36,352.19	51,187.19
Contingency (5%TMC)	3,268.71	3,498.71	4,208.09	4,649.34	4,851.20	6,058.70	8,531.20
Freight % Handling (5% TMC)	3,268.71	3,498.71	4,208.09	4,649.34	4,851.20	6,058.70	8,531.20
TOTAL	91,523.79	97,963.79	117,826.40	130,181.63	135,833.53	169,643.53	238,873.53

9.2 ANNEX B: PERFORMANCE ANALYSIS ASSESSMENT DETAILS

9.2.1 Load Forecasting:

Energy Sale Forecast

Per Feeder Sales (KWR)

Forecasted Sales are being evaluated by the result on its test criteria as discuss in the previous chapter. Table below shows the acceptable result of the preferred model equation for energy sales forecasting.

Feeder	TYPE of Consumer	Model No.	Equation	Remarks	$R^2 > 0.99$	$R^2_{adjusted} > 0.99$	MAPE < = 3%
Direct Forecast	Overall	1	a(t) + b	Passed	0.9929	0.9915	1.01%

t - stat > 2 & < -2				P - Value < 0.1				GROWTHRATE			
a	b	c	d	a	b	c	d	*Predicted*	*1-5 year*	*6-10 year*	*11-20 year*
26.4715	61.2741	N/A	N/A	0.000	0.000	N/A	N/A	7.33%	4.94%	4%	3%

Direct Forecasting Method

FEEDER	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	8,777.26	9,367.98	9,693.64	10,024.15	10,358.74	10,696.73	11,037.53	11,380.66	11,725.71	12,072.33	12,420.21
SAF2	5,817.42	6,247.06	6,566.41	6,888.25	7,212.11	7,537.60	7,864.40	8,192.26	8,520.94	8,850.24	9,179.99
SAF3	1,015.03	1,071.85	1,119.31	1,165.37	1,210.14	1,253.70	1,296.12	1,337.47	1,377.79	1,417.14	1,455.56
SBF1	3,485.43	3,781.56	4,065.28	4,366.61	4,686.22	5,024.68	5,382.52	5,760.17	6,158.05	6,576.50	7,015.85
SBF2	3,409.04	3,590.83	3,719.71	3,845.30	3,967.72	4,087.05	4,203.40	4,316.88	4,427.57	4,535.56	4,640.96
SBF3	3,469.21	3,639.89	3,751.75	3,861.25	3,968.32	4,072.98	4,175.22	4,275.08	4,372.60	4,467.83	4,560.82
SCF1	7,920.75	8,881.97	9,658.33	10,448.46	11,251.12	12,065.24	12,889.87	13,724.18	14,567.39	15,418.80	16,277.76
SCF2	8,426.87	8,863.89	9,240.87	9,606.76	9,962.26	10,307.98	10,644.43	10,972.08	11,291.35	11,602.60	11,906.16
SDF1	6,841.59	7,167.34	7,465.95	7,755.90	8,037.72	8,311.86	8,578.70	8,838.62	9,091.91	9,338.86	9,579.73
SDF2	11,342.84	12,083.78	12,712.59	13,339.97	13,965.70	14,589.60	15,211.52	15,831.33	16,448.91	17,064.17	17,677.03
SDF3	4,757.98	5,215.80	5,588.05	5,962.30	6,338.41	6,716.24	7,095.63	7,476.44	7,858.52	8,241.70	8,625.87
SDF4	982.66	1,057.06	1,104.84	1,151.16	1,196.11	1,239.80	1,282.28	1,323.64	1,363.92	1,403.18	1,441.47
SEF1	3,515.35	3,786.43	4,000.44	4,207.02	4,406.88	4,600.59	4,788.63	4,971.39	5,149.20	5,322.35	5,491.10
SEF2	1,831.55	1,957.56	2,070.31	2,179.11	2,284.35	2,386.33	2,485.31	2,581.50	2,675.07	2,766.19	2,854.99
SEF3	7,300.08	7,959.38	8,536.94	9,116.38	9,697.42	10,279.82	10,863.34	11,447.78	12,032.95	12,618.67	13,204.76

SFF1	1,647.61	1,722.30	1,796.80	1,869.09	1,939.31	2,007.58	2,074.01	2,138.69	2,201.71	2,263.14	2,323.06
SFF2	2,506.34	2,605.12	2,709.25	2,810.46	2,908.91	3,004.72	3,098.03	3,188.94	3,277.56	3,363.98	3,448.29
SFF3	1,647.06	1,844.58	1,994.07	2,147.17	2,303.46	2,462.59	2,624.29	2,788.30	2,954.44	3,122.50	3,292.33
TOTAL	**86,404.74**	**90,844.37**	**95,794.54**	**100,744.72**	**105,694.89**	**110,645.07**	**115,595.24**	**120,545.41**	**125,495.59**	**130,445.76**	**135,395.93**

Per Feeder Demand (MW)

Forecasted Demand are derive based on the formula:

$$\boldsymbol{Demand}_{system} = \frac{Energy\ Forecast_{system}}{\boldsymbol{L.F}_{system} \times \mathbf{8760}}$$ where, LF = 0.58 based on year 2015

FEEDER	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	2.13	2.24	2.32	2.39	2.47	2.55	2.63	2.71	2.79	2.87
SAF2	1.47	1.52	1.59	1.67	1.74	1.82	1.89	1.97	2.05	2.12
SAF3	0.25	0.26	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34
SBF1	1.15	1.21	1.30	1.40	1.50	1.60	1.71	1.83	1.96	2.09
SBF2	1.09	1.11	1.14	1.18	1.22	1.25	1.29	1.32	1.35	1.38
SBF3	1.11	1.12	1.15	1.18	1.21	1.24	1.27	1.30	1.33	1.36
SCF1	2.12	2.26	2.44	2.63	2.82	3.01	3.21	3.41	3.60	3.81
SCF2	2.12	2.16	2.25	2.33	2.41	2.49	2.57	2.64	2.71	2.78
SDF1	1.59	1.62	1.68	1.75	1.80	1.86	1.92	1.97	2.03	2.08
SDF2	2.68	2.76	2.90	3.03	3.17	3.30	3.44	3.57	3.70	3.84
SDF3	1.16	1.21	1.29	1.38	1.46	1.54	1.62	1.71	1.79	1.87
SDF4	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.30	0.31
SEF1	0.86	0.89	0.94	0.99	1.03	1.07	1.11	1.15	1.19	1.23
SEF2	0.45	0.46	0.49	0.51	0.53	0.56	0.58	0.60	0.62	0.64
SEF3	1.82	1.91	2.04	2.17	2.30	2.43	2.56	2.69	2.82	2.95
SFF1	0.46	0.47	0.49	0.51	0.52	0.54	0.56	0.58	0.59	0.61
SFF2	0.69	0.71	0.73	0.76	0.79	0.81	0.83	0.86	0.88	0.90
SFF3	0.49	0.52	0.56	0.60	0.64	0.69	0.73	0.77	0.82	0.86

Per Feeder Forecasted Purchased (MWH)

Forecasted Purchased are derive based on the formula:

$$Forecasted\ Purchased = Forecasted\ Sales\ +\ System\ Loss_{Simulated\ result\ in\ DSAS}$$

FEEDER	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	10,204.24	10,507.38	10,901.64	11,303.89	11,713.67	12,030.87	12,438.36	12,850.22	13,266.09	13,685.65
SAF2	6,853.94	7,158.85	7,521.50	7,888.35	8,259.00	8,633.12	9,010.45	9,390.74	9,773.80	10,159.46
SAF3	1,226.33	1,272.74	1,321.74	1,369.40	1,416.14	1,461.90	1,506.74	1,550.69	1,593.83	1,636.18
SBF1	4,116.55	4,432.73	4,757.21	5,101.04	5,464.82	5,851.09	6,259.57	6,690.88	7,145.59	7,624.26
SBF2	3,902.68	4,025.57	4,168.03	4,308.08	4,445.80	4,581.31	4,714.67	4,845.99	4,975.35	5,102.84
SBF3	3,925.86	4,033.12	4,155.57	4,276.18	4,394.92	4,511.81	4,626.86	4,740.11	4,851.60	4,961.38
SCF1	9,643.85	10,403.09	11,241.38	12,094.16	12,960.31	13,838.85	14,728.87	15,629.56	16,540.18	17,460.02
SCF2	9,777.70	10,132.61	10,542.33	10,944.29	11,339.25	11,727.89	12,110.87	12,488.77	12,862.17	13,231.61
SDF1	8,166.38	8,442.70	8,795.40	9,142.72	9,484.99	9,822.51	10,155.52	10,484.25	10,808.89	11,129.63
SDF2	13,198.84	13,796.94	14,510.58	15,225.79	15,942.28	16,659.82	17,378.19	18,097.21	18,834.35	19,578.80
SDF3	5,670.44	6,032.82	6,434.86	6,874.00	7,247.95	7,658.69	8,072.01	8,492.52	8,917.24	9,346.28
SDF4	1,266.66	1,314.44	1,326.41	1,374.10	1,420.63	1,466.08	1,510.50	1,553.96	1,596.51	1,638.20
SEF1	4,415.24	4,612.02	4,867.38	5,119.08	5,368.02	5,618.00	5,868.48	6,120.33	6,374.44	6,631.70
SEF2	2,170.16	2,279.69	2,397.57	2,512.32	2,624.26	2,733.64	2,840.68	2,945.56	3,048.42	3,149.40
SEF3	8,629.60	9,190.41	9,817.06	10,447.50	11,081.48	11,718.75	12,359.08	12,136.90	12,722.62	13,308.72
SFF1	1,918.41	1,990.55	2,069.54	2,146.81	2,222.47	2,296.65	2,369.44	2,440.91	2,511.16	2,580.24
SFF2	2,887.91	2,986.72	3,102.93	3,217.15	3,329.50	3,440.13	3,549.14	3,656.67	3,743.09	3,867.69
SFF3	2,078.97	2,224.76	2,388.30	2,555.59	2,726.30	2,900.13	3,076.85	3,256.25	3,438.14	3,622.38
TOTAL	**100,053.76**	**104,837.15**	**110,319.44**	**115,900.44**	**121,441.81**	**126,951.23**	**132,576.27**	**137,371.53**	**143,003.48**	**148,714.42**

Per Feeder Forecasted No. of consumer

The forecast model for number of consumer are being decided or based on the result of its criteria are discuss in previous chapter.

$$Forecasted\ no. of\ Consumer = \sum_{SAF1}^{SFF3} Forecasted\ Customer_{per\ Feeder}$$

Test criteria result A

Feeder	TYPE of Consumer	Model No.	Equation	Remarks	$R^2 > 0.99$	$R^2_{adjusted} > 0.99$	MAPE < = 3%
SAF1	ALL	**22**	a(logt) +b(t) +c	Passed	1.00	1.00	0.00
SAF2	ALL	**22**	a(logt) +b(t) +c	Passed	0.99	0.99	0.01
SAF3	ALL	**22**	a(logt) +b(t) +c	Passed	0.99	0.99	0.00
SBF1	ALL	**1**	a(t) + b	Passed	0.99	0.99	0.01
SBF2	ALL	**11**	a(lnt^2) + b	Passed	1.00	1.00	0.00

SBF3	ALL	**11**	a(lnt^2) + b	Passed	1.00	1.00	0.00
SCF1	ALL	**11**	a(lnt^2) + b	Passed	0.99	0.99	0.01
SCF2	ALL	**28**	a(t^-1) + b(t) + c	Passed	1.00	0.99	0.01
SDF1	ALL	**11**	a(lnt^2) + b	Passed	0.97	0.97	0.02
SDF2	ALL	**22**	a(logt) +b(t) +c	Passed	0.99	0.98	0.02
SDF3	ALL	**22**	a(logt) +b(t) +c	Passed	1.00	1.00	0.00
SDF4	ALL	**22**	a(logt) +b(t) +c	Passed	0.99	0.99	0.01
SEF1	ALL	**22**	a(logt) +b(t) +c	Passed	1.00	0.99	0.01
SEF2	ALL	**11**	a(lnt^2) + b	Passed	1.00	1.00	0.01
SEF3	ALL	**11**	a(lnt^2) + b	Passed	0.99	0.99	0.01
SFF1	ALL	**11**	a(lnt^2) + b	Passed	0.99	0.99	0.01
SFF2	ALL	**2**	a(t^2) + b(t) + c	Passed	0.99	0.99	0.00
SFF3	ALL	**11**	a(lnt^2) + b	Passed	0.99	0.99	0.01

Test criteria result A(cont.)

Equation	**Remarks**	**t - stat > 2 & < -2**				**P - Value < 0.1**				**GROWTHRATE**			
		a	**b**	**c**	**d**	**a**	**b**	**c**	**d**	*Predicted*	*1-5 year*	*6-10 year*	*11-20 year*
a(logt) +b(t) +c	Passed	4.25	12.03	438.93	N/A	0.01	0.00	0.00	N/A	3%	2%	2%	2%
a(logt) +b(t) +c	Passed	-4.10	10.46	102.87	N/A	0.01	0.00	0.00	N/A	4%	5%	4%	3%
a(logt) +b(t) +c	Passed	-2.84	9.41	155.20	N/A	0.05	0.00	0.00	N/A	3%	3%	3%	2%
a(t) + b	Passed	26.04	119.15	N/A	N/A	0.00	0.00	N/A	N/A	4%	3%	3%	2%
a(lnt^2) + b	Passed	36.70	232.60	N/A	N/A	0.00	0.00	N/A	N/A	4%	2%	2%	1%
a(lnt^2) + b	Passed	78.80	541.49	N/A	N/A	0.00	0.00	N/A	N/A	4%	2%	2%	1%
a(lnt^2) + b	Passed	25.51	112.68	N/A	N/A	0.00	0.00	N/A	N/A	5%	3%	2%	1%
a(t^-1) + b(t) + c	Passed	3.01	19.47	36.49	N/A	0.04	0.00	0.00	N/A	5%	4%	4%	3%
a(lnt^2) + b	Passed	13.83	37.05	N/A	N/A	0.00	0.00	N/A	N/A	8%	4%	3%	2%
a(logt) +b(t) +c	Passed	-2.54	7.74	35.88	N/A	0.06	0.00	0.00	N/A	8%	7%	5%	4%
a(logt) +b(t) +c	Passed	-2.53	18.11	152.14	N/A	0.06	0.00	0.00	N/A	7%	5%	4%	3%
a(logt) +b(t) +c	Passed	-4.43	11.41	124.88	N/A	0.01	0.00	0.00	N/A	4%	4%	4%	3%
a(logt) +b(t) +c	Passed	3.96	3.83	76.23	N/A	0.02	0.02	0.00	N/A	7%	3%	3%	2%
a(lnt^2) + b	Passed	38.78	109.21	N/A	N/A	0.00	0.00	N/A	N/A	8%	4%	3%	2%
a(lnt^2) + b	Passed	27.23	72.46	N/A	N/A	0.00	0.00	N/A	N/A	8%	4%	3%	2%
a(lnt^2) + b	Passed	27.46	124.26	N/A	N/A	0.00	0.00	N/A	N/A	5%	3%	2%	1%
a(t^2) + b(t) + c	Passed	2.84	2.88	88.79	N/A	0.05	0.04	0.00	N/A	3%	5%	5%	5%

9.2.2 Power Quality Analysis

Voltage Profile

YEAR	GARCIA SUBSTATION								
	Feeder 1			Feeder 2			Feeder 3		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.86	0.93	0.92	0.84	0.96	0.86	1.00	1.00	0.97
2017	0.86	0.93	0.92	0.85	0.96	0.86	1.00	1.00	0.97
2018	0.86	0.93	0.92	0.84	0.96	0.86	1.00	1.00	0.97
2019	0.85	0.93	0.91	0.83	0.96	0.85	1.00	1.00	0.97
2020	0.85	0.93	0.91	0.82	0.95	0.84	1.00	1.00	0.97
2021	0.84	0.92	0.91	0.81	0.95	0.83	1.00	1.00	0.97
2022	0.84	0.92	0.90	0.80	0.95	0.82	1.00	1.00	0.97
2023	0.84	0.92	0.90	0.79	0.95	0.81	1.00	1.00	0.96
2024	0.84	0.92	0.90	0.79	0.94	0.80	1.00	1.00	0.96
2025	0.84	0.92	0.90	0.77	0.94	0.79	1.00	1.00	0.96

YEAR	GUINDULMAN SUBSTATION								
	Feeder 1			Feeder 2			Feeder 3		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.93	0.97	0.97	0.97	0.96	0.96	0.97	0.99	0.98
2017	0.93	0.97	0.97	0.97	0.96	0.96	0.97	0.99	0.98
2018	0.92	0.96	0.97	0.97	0.95	0.96	0.97	0.99	0.97
2019	0.92	0.96	0.97	0.97	0.95	0.96	0.97	0.99	0.97
2020	0.92	0.96	0.97	0.96	0.95	0.96	0.96	0.97	0.97
2021	0.92	0.96	0.97	0.96	0.95	0.96	0.96	0.98	0.97
2022	0.92	0.95	0.97	0.96	0.95	0.96	0.96	0.98	0.97
2023	0.92	0.95	0.97	0.96	0.95	0.95	0.96	0.98	0.97
2024	0.92	0.95	0.97	0.96	0.95	0.95	0.96	0.98	0.97
2025	0.92	0.95	0.97	0.96	0.95	0.95	0.96	0.98	0.97

YEAR	ALICIA SUBSTATION					
	Feeder 1			Feeder 2		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.83	0.87	0.92	0.91	0.96	0.97
2017	0.83	0.87	0.92	0.91	0.96	0.97

2018	0.82	0.87	0.92	0.91	0.96	0.97
2019	0.82	0.87	0.92	0.91	0.96	0.97
2020	0.82	0.87	0.92	0.90	0.96	0.97
2021	0.81	0.86	0.91	0.90	0.96	0.97
2022	0.81	0.86	0.91	0.90	0.96	0.97
2023	0.81	0.86	0.91	0.90	0.96	0.97
2024	0.80	0.86	0.90	0.89	0.96	0.97
2025	0.80	0.86	0.90	0.89	0.96	0.97

YEAR	TRINIDAD SUBSTATION											
	Feeder 1			Feeder 2			Feeder 3			Feeder 3		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.84	0.83	0.94	0.94	0.89	0.91	0.99	0.92	0.99	0.99	0.98	1.00
2017	0.84	0.83	0.95	0.94	0.89	0.91	0.99	0.92	0.99	0.99	0.98	1.00
2018	0.83	0.82	0.94	0.94	0.89	0.91	0.99	0.91	0.99	0.99	0.98	1.00
2019	0.82	0.80	0.93	0.94	0.89	0.91	0.99	0.91	0.99	0.99	0.97	1.00
2020	0.81	0.80	0.93	0.94	0.89	0.91	0.99	0.90	0.99	0.99	0.97	1.00
2021	0.81	0.80	0.93	0.94	0.89	0.91	0.99	0.90	0.99	0.99	0.97	1.00
2022	0.81	0.80	0.93	0.94	0.89	0.91	0.99	0.90	0.99	0.99	0.97	1.00
2023	0.81	0.79	0.93	0.93	0.89	0.90	0.99	0.90	0.99	0.99	0.97	1.00
2024	0.81	0.79	0.93	0.93	0.89	0.90	0.99	0.90	0.99	0.99	0.97	1.00
2025	0.81	0.79	0.93	0.93	0.89	0.90	0.99	0.90	0.99	0.99	0.97	1.00

YEAR	IMELDA SUBSTATION								
	Feeder 1			Feeder 2			Feeder 3		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.94	0.94	0.92	1.00	0.93	0.99	0.89	0.95	0.92
2017	0.94	0.94	0.92	1.00	0.93	0.99	0.89	0.95	0.92
2018	0.93	0.94	0.92	1.00	0.93	0.99	0.89	0.94	0.91
2019	0.93	0.94	0.92	1.00	0.92	0.99	0.88	0.94	0.91
2020	0.93	0.93	0.92	1.00	0.92	0.99	0.87	0.93	0.90
2021	0.93	0.93	0.91	1.00	0.91	0.99	0.87	0.93	0.90
2022	0.93	0.93	0.91	1.00	0.91	0.99	0.86	0.93	0.89
2023	0.93	0.92	0.91	1.00	0.91	0.98	0.86	0.93	0.89
2024	0.93	0.92	0.91	1.00	0.90	0.98	0.86	0.93	0.89
2025	0.93	0.92	0.91	1.00	0.90	0.98	0.86	0.93	0.89

YEAR	MAHAYAG SUBSTATION								
	Feeder 1			Feeder 2			Feeder 3		
	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C	PHASE A	PHASE B	PHASE C
2016	0.98	1.00	0.97	0.93	1.00	0.98	0.93	1.00	0.94
2017	0.98	1.00	0.97	0.93	1.00	0.98	0.93	1.00	0.94
2018	0.98	1.00	0.97	0.92	1.00	0.98	0.93	1.00	0.94
2019	0.98	1.00	0.96	0.92	1.00	0.97	0.92	1.00	0.94
2020	0.97	1.00	0.96	0.91	1.00	0.97	0.92	1.00	0.94
2021	0.97	1.00	0.96	0.91	1.00	0.97	0.91	1.00	0.93
2022	0.97	1.00	0.96	0.91	1.00	0.97	0.91	1.00	0.93
2023	0.97	1.00	0.96	0.90	1.00	0.97	0.91	1.00	0.93
2024	0.97	1.00	0.95	0.90	1.00	0.97	0.90	1.00	0.92
2025	0.97	1.00	0.95	0.90	1.00	0.97	0.90	1.00	0.92

Unbalanced percentage Voltage Profile

SUBSTATION	FEEDER	Electrically Farthest Section	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	SAF1	SAF1_123-95	3.3%	3.2%	3.3%	3.5%	3.6%	3.8%	2.8%	3.0%	3.2%	3.3%
	SAF2	SAF2_186	3.2%	6.0%	6.4%	6.8%	7.2%	7.7%	8.1%	8.6%	9.1%	9.6%
	SAF3	SAF3_136	1.2%	1.1%	1.2%	1.2%	1.3%	1.4%	1.4%	1.5%	1.5%	1.6%
	SBF1	SBF1_214	2.4%	2.4%	2.6%	2.5%	2.4%	2.5%	2.4%	2.6%	2.3%	2.4%
	SBF2	SBF2_165	7.7%	7.6%	7.9%	8.3%	8.6%	8.5%	8.4%	7.2%	7.5%	7.8%
	SBF3	SBF3_77	1.3%	1.3%	1.3%	1.4%	1.5%	1.6%	1.6%	1.7%	1.8%	1.8%
	SCF1	SCF1_210	5.9%	5.8%	6.2%	6.0%	6.0%	6.3%	5.2%	5.5%	5.7%	6.0%
	SCF2	SCF2_220-3	4.6%	4.5%	4.5%	4.4%	4.7%	4.2%	4.4%	4.7%	4.5%	4.5%
	SDF1	SDF1_292	9.0%	8.8%	9.4%	10.0%	1.1%	1.0%	9.8%	1.0%	1.1%	1.0%
	SDF2	SDF2_121	3.0%	3.0%	2.9%	3.0%	2.9%	3.0%	2.8%	3.0%	2.9%	3.0%
	SDF3	SDF3_43-111	5.3%	5.2%	5.5%	5.4%	6.1%	5.9%	6.2%	6.2%	6.0%	6.0%
	SDF4	SDF4_80	0.0%	0.7%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%
	SEF1	SEF1_101	2.8%	2.7%	2.8%	2.8%	2.8%	2.4%	2.5%	2.6%	2.7%	2.8%
	SEF2	SEF2_159	4.0%	4.0%	4.2%	4.4%	4.6%	4.9%	5.1%	5.3%	5.6%	5.8%
	SEF3	SEF3_190-47	3.4%	3.3%	3.5%	3.7%	3.8%	4.0%	4.2%	4.2%	4.2%	4.2%
	SFF1	SFF1_90	1.7%	1.7%	1.7%	1.8%	1.9%	2.0%	2.1%	2.2%	2.3%	2.4%
	SFF2	SFF2_131	3.58%	3.51%	3.70%	3.89%	4.08%	4.27%	4.47%	4.66%	4.85%	4.91%

MAHAYAG SUBSTATION 5MVA	SFF3	SFF3_290	0.67%	0.65%	0.69%	0.73%	0.77%	0.82%	0.86%	0.90%	0.94%	0.98%

9.2.3 Efficiency Analysis

Forecasted Per Feeder KWH Loss

Feeder	ANNUAL TECHNICAL LOSS PER FEEDER (KWH)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAF1	836,263	813,738	877,486	945,147	1,016,947	993,342	1,057,692	1,124,507	1,193,764	1,265,440
SAF2	606,886	592,431	633,250	676,245	721,405	768,721	818,188	869,802	923,560	979,466
SAF3	154,476	153,435	156,374	159,257	162,444	165,781	169,267	172,902	176,686	180,620
SBF1	334,988	367,445	390,600	414,827	440,136	468,568	499,399	532,833	569,089	608,404
SBF2	311,847	305,861	322,725	340,359	358,754	377,902	397,796	418,428	439,791	461,880
SBF3	285,972	281,370	294,328	307,856	321,946	336,590	351,781	367,512	383,774	400,562
SCF1	761,880	744,762	792,915	843,036	895,073	948,975	1,004,691	1,062,174	1,121,378	1,182,260
SCF2	913,809	891,739	935,570	982,028	1,031,271	1,083,464	1,138,784	1,197,420	1,259,569	1,325,443
SDF1	999,035	976,752	1,039,503	1,105,003	1,173,138	1,243,805	1,316,903	1,392,341	1,470,031	1,549,892
SDF2	1,115,053	1,084,349	1,170,616	1,260,090	1,352,680	1,448,298	1,546,862	1,648,295	1,770,181	1,901,777
SDF3	454,642	444,769	472,559	535,586	531,709	563,052	595,568	634,004	675,535	720,411
SDF4	209,603	209,603	175,254	177,992	180,839	183,795	186,861	190,037	193,325	196,725
SEF1	628,817	611,580	660,364	712,204	767,430	829,369	897,090	971,134	1,052,090	1,140,603
SEF2	212,596	209,380	218,450	227,966	237,928	248,334	259,186	270,483	282,225	294,414
SEF3	670,227	653,479	700,678	750,082	801,666	855,411	911,303	103,952	103,952	103,952
SFF1	196,118	193,744	200,445	207,495	214,894	222,645	230,747	239,204	248,015	257,184
SFF2	282,787	277,469	292,474	308,242	324,780	342,096	360,200	379,107	379,107	419,396
SFF3	234,389	230,693	241,133	252,138	263,707	275,840	288,541	301,809	315,647	330,057
TOTAL	9,209,388	9,042,601	9,574,726	10,205,553	10,796,745	11,355,986	12,030,859	11,875,942	12,557,721	13,318,487

9.3 ANNEX C: ECONOMIC LINE AND TRANSFORMER SIZING

Lines and transformers are the basic elements of a distribution system. Voltage is both a performance criteria and a resource to be used well. In a well-designed distribution system, line and transformer size will be proportional to loading level. It is important to size lines and transformers so that they are able to carry the load, maintain the voltage levels at prescribed levels, and minimize losses. Economic sizing of lines and transformers account for all costs – initial and continuing, and allows us to choose the size that will carry load within standards while achieving the least-cost. In table 4-1 shows the different conductors and their corresponding present worth costs versus its loading in kilowatt. The point of intersection of the various total present worth cost in the graph represents the economic loading of each of the conductors. Also, the economic sizing of transformer is shown in Table 4-2 between amorphous and silicon core transformer.

Table 9-1. Summary Economic Line Sizing

Conductor Size	Phase	ECONOMIC LOAD RANGE (KW)		Voltage Drop		Economic Load Reach
		Min. load	Max Load	Volts/km	% / km	
4	1	Not Feasible				
2	1	0	178	31.07	0.41%	18.40
1/0	1	Not Feasible				
2/0	1	Not Feasible				
3/0	1	Not Feasible				
4/0	1	Not Feasible				

336400	**1**	Not Feasible				
4	**3**	Not Feasible				
2	**3**	178	274	19.97	0.26%	28.62
1/0	**3**	274	342	17.23	0.23%	33.17
2/0	**3**	342	411	16.94	0.22%	33.74
3/0	**3**	Not Feasible				
4/0	**3**	411	946	26.67	0.35%	21.43
336400	**3**	946	-			

DISTRIBUTION TRANSFORMER ECONOMIC SIZING			
		Initial Peak load (KVA)	
		Lower-Bound	Upper-Bound
5	Silicon	Not Feasible	
10	Silicon	4.67	8.32
15	Silicon	Not Feasible	
25	Silicon	Not Feasible	
37.5	Silicon	Not Feasible	
5	Amorphous	0	4.67
10	Amorphous	Not Feasible	
15	Amorphous	Not Feasible	
25	Amorphous	8.32	14.71
37.5	Amorphous	14.71	-

Table 9-2. Summary Transformer Economic Sizing

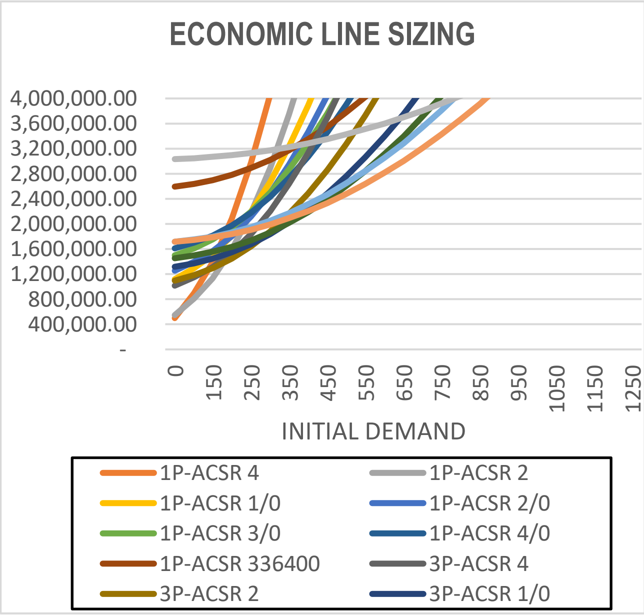


Figure 9-2. Economic Line Sizing

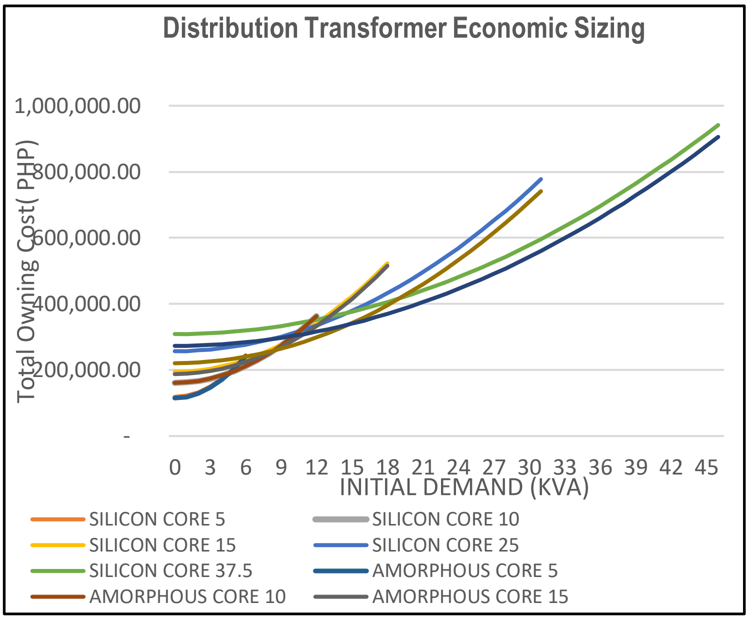


Figure 9-1. Economic Transformer Sizing.