

GEOFF BROWN & ASSOCIATES LTD

**PERFORMANCE BASED RATE SETTING
REVIEW OF FORECAST CAPITAL EXPENDITURE FOR THE SECOND
REGULATORY PERIOD**

VISAYAN ELECTRIC COMPANY (VECO)

Prepared for
ENERGY REGULATORY COMMISSION

**Final
23 November 2009**

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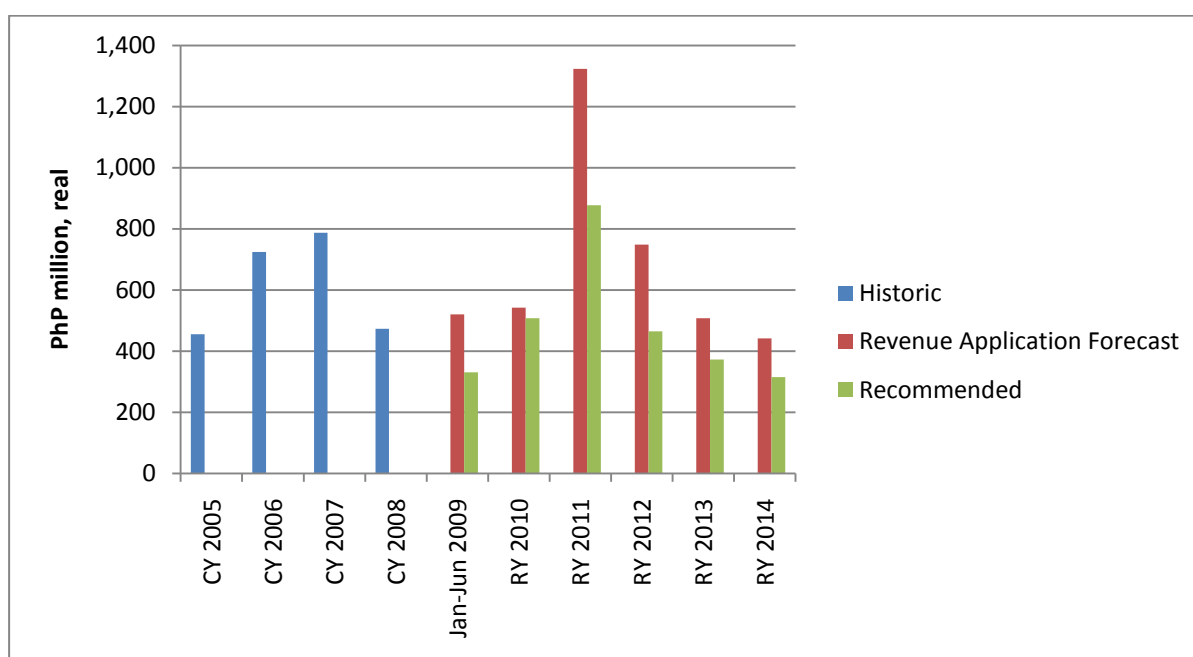
EXECUTIVE SUMMARY**TOTAL CAPEX**

A comparison of our recommended total CAPEX with VECO's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of VECO Forecast and Recommended CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
VECO Forecast	520.28	541.63	1,323.46	748.02	507.78	442.15	3,021.41
Recommended	331.00	507.46	877.08	464.48	372.50	315.28	2,029.34
Adjustment	(189.28)	(34.17)	(446.38)	(283.54)	135.28	126.87	(992.07)
Impact of Adjustment	(36%)	(6%)	(34%)	(38%)	27%	29%	(33%)

A comparison of the recommended and forecast CAPEX with actual expenditure over the historical period CY 2005-08 is shown in the figure below.

Comparison of Forecast, Recommended and Historical Total CAPEX**MAJOR PROJECTS**

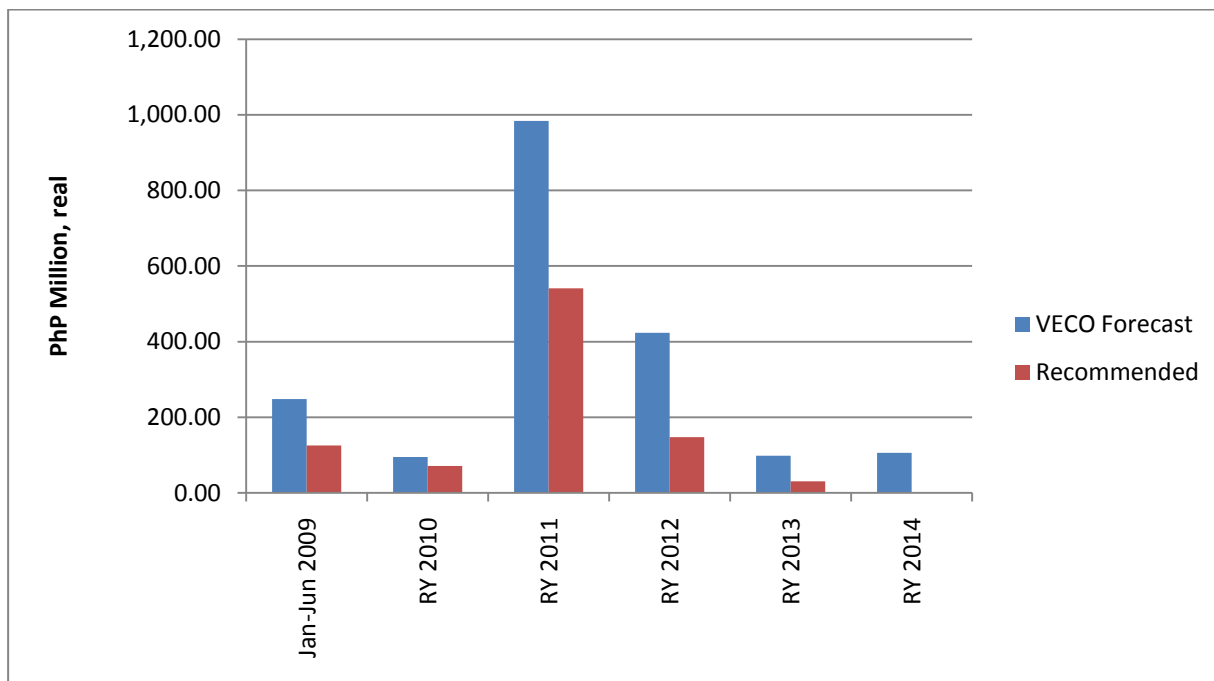
A comparison of our recommended total major project CAPEX with VECO's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of VECO Forecast and Recommended CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
VECO Forecast	247.96	94.84	984.11	422.95	98.62	106.27	1,611.95
Recommended	125.50	71.23	540.99	147.38	30.49	-	718.86
Adjustment	(122.46)	(23.61)	(443.12)	(275.57)	(68.13)	(106.27)	(893.09)
Impact of Adjustment	(49%)	(25%)	(45%)	(65%)	(69%)	(100%)	(55%)

The recommended and forecast major project CAPEX is also shown in the figure below. VECO did not provide its historical major project CAPEX in its revenue application.

Comparison of Recommended and Forecast Major Project CAPEX



The reasons for our recommended reductions to VECO’s major CAPEX forecast are discussed below.

- VECO is proposing construct a major Php1.20 billion, 138 kV project in RY 2011-12 comprising two 138 kV transmission lines and a new 100 MVA, 138 kV substation. The project is designed to deliver power from a new coal fired power station presently being constructed by the Cebu Energy Development Corporation (CEDC) to VECO’s subtransmission system, bypassing the NGCP grid. VECO has justified its proposal by showing that the costs paid by its customers for power delivery through this bypass will be less than if the power was delivered using the NGCP grid.

We consider that, from an engineering perspective only one of the two transmission lines proposed by VECO (between the CEDC power station and Naga) is required and that the function of the proposed new substation and the second transmission line (between Naga and Quiot) can be performed using existing NGCP assets. We also consider the bypass solution proposed by VECO to be technically inferior to the use of NGCP assets.

We have confirmed that the bypass solution proposed by VECO will indeed reduce the power delivery charges paid by VECO’s customers. However the bypass will also deprive NGCP of revenue, which will need to be made up by all users of NGCP’s Visayas shared transmission grid. The total power delivery costs that would be paid by all Visayas consumers will be higher if VECO’s bypass solution is implemented than if existing NGCP assets were used where capacity is available.

We recommend that only the proposed new 138 kV transmission line between the new CEDC power station and Naga proceed and that it be operated as part of the NGCP grid. We have included the cost of constructing the line in VECO’s recommended CAPEX as it now appears unlikely that NGCP would be able to build the line in time for commissioning of the new CEDC power station. The legal and commercial arrangements through which NGCP will operate the line as part of its grid and the impact of this arrangement on the pricing of transmission services will need to be negotiated between NGCP and VECO and approved by the ERC.

- VECO's CAPEX forecast provides for the installation of eight new 138/69 kV power transformers with a total additional capacity of 264 MVA, when the total additional load between 2008 and 2014 is forecast to be only 61 MVA. Our recommended CAPEX allows for the installation of only three new 33 MVA transformers. We believe there is potential for VECO to optimize the loading of its existing power transformers by reviewing the location of the normally open points within its distribution network.
- VECO has proposed the construction of a new 69 kV switching station at Ermita, since it believes that this will provide greater operating flexibility and higher reliability. We do not consider that this switching station should proceed as our analysis indicates that any benefits of this switching station are marginal and do not justify the forecast costs and have not included this project in our recommended CAPEX forecast.
- We recommend that funding for the proposed purchase of subtransmission assets from NGCP be included in the CAPEX forecast, subject to relatively minor adjustments to the amounts provided for the purchase of the Naga-Sibonga and Banilad-Cotcot subtransmission lines. We also consider that the purchase of the Quiot transformer should be on condition that the transformer is not disconnected from the NGCP grid without prior ERC approval, since such disconnection could potentially reduce the reliability of supply to customers and will also make recently constructed NGCP assets redundant. Since the cost and timing of asset acquisitions from NGCP is uncertain, we suggest the final determination include a provision for an adjustment at the time of the next price reset to reflect any difference between the amount provided in the allowed CAPEX for the purchase of NGCP assets and the amount actually spent.
- We recommend that VECO's contribution towards the cost of the Oracle customer care and billing system that the Aboitiz Power Company (APC) is planning to purchase for all its utilities be included in the allowed CAPEX, subject to a minor adjustment to the timing of this expenditure. Our proposed timing is consistent with the delivery schedule in Oracle's proposal and with the timing of the expenditure in DLPC's revenue application.

RESIDUAL GROWTH CAPEX

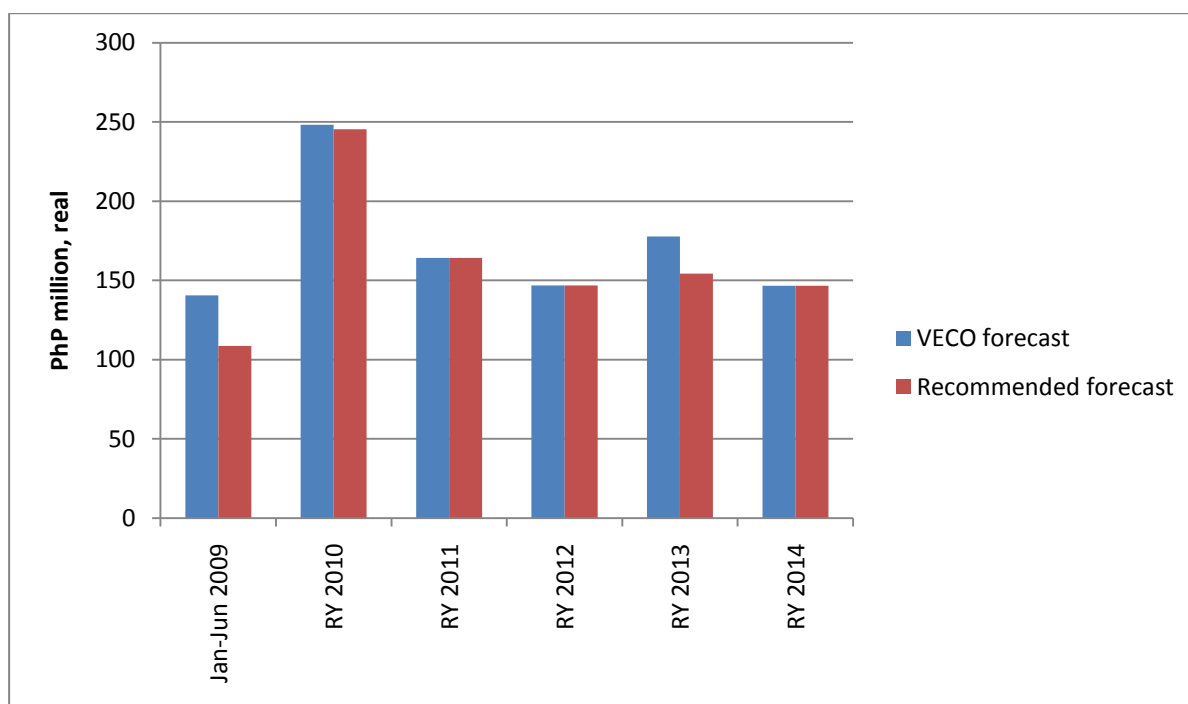
A comparison of our recommended residual growth CAPEX with VECO's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of VECO Forecast and Recommended Residual Growth CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
VECO Forecast	140.52	248.28	164.24	146.73	177.79	146.57	635.33
Recommended	108.54	245.37	164.24	146.73	154.34	146.57	611.88
Adjustment	(31.98)	(2.91)	-	-	23.45	-	23.45
Impact of Adjustment	23%	1%	-	-	13%	-	4%

The recommended and forecast residual growth CAPEX is also shown in the figure below. VECO did not provide its historical residual growth CAPEX in its revenue application.

Comparison of Recommended and Forecast Residual Growth CAPEX



We recommend that:

- funding for the purchase of a 105 ft articulating folding boom and a 4 drum puller in the period Jan-Jun 2009 not be included in the allowed CAPEX. This equipment is highly specialized construction equipment and, in our view, is not justified by the volume of new line construction work included in our recommended CAPEX.
- funding for the purchase of laboratory equipment over the period Jan 2009–Jun 2010 not be included in the allowed CAPEX as VECO has provided no information as to what the equipment is, how frequently it will be used and whether it is possible to hire the equipment from NGCP or other parties.
- funding for the purchase of some network assets in RY 2013 not be included in the allowed CAPEX. This CAPEX appears to relate to a single one-off project, which VECO has not described. We think that the expenditure is most likely for the protection and metering of the proposed 138 kV Naga-Quiot line, which we have recommended not proceed.

RESIDUAL RENEWAL CAPEX

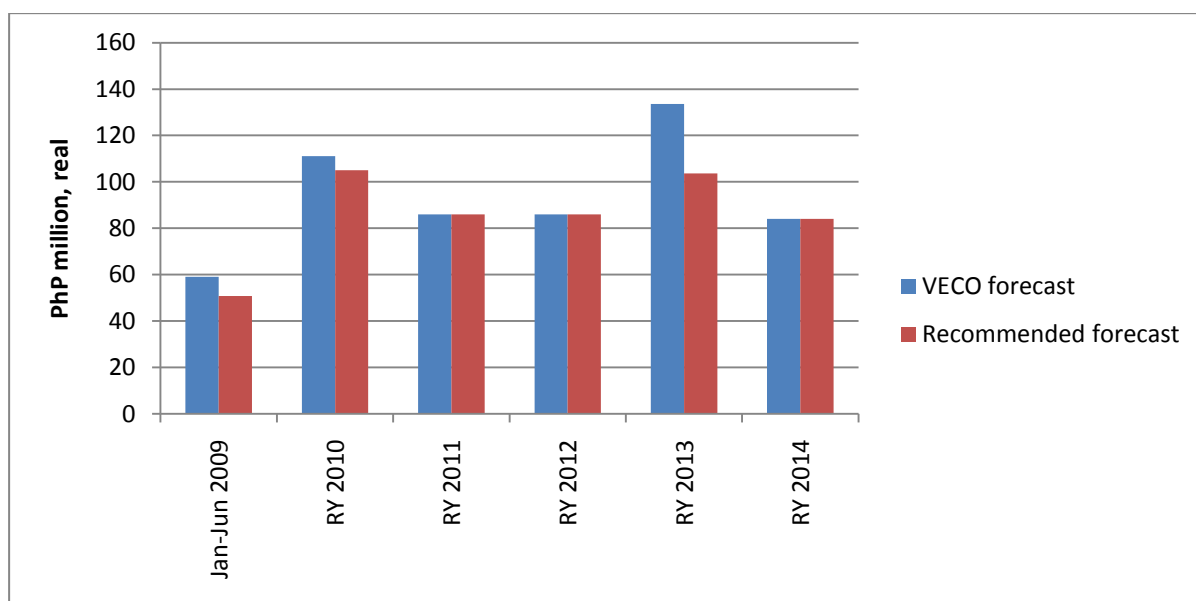
A comparison of our recommended total residual renewal CAPEX with VECO's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of VECO Forecast and Recommended Residual Renewal CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
VECO Forecast	59.06	111.17	86.02	85.99	133.52	84.08	389.61
Recommended	50.76	105.02	86.02	85.99	103.68	84.08	359.77
Adjustment	(8.30)	(6.15)	-	-	(29.84)	-	(29.84)
Impact of Adjustment	(14%)	(6%)	-	-	(22%)	-	(8%)

The recommended and forecast residual renewal CAPEX is also shown in the figure below. VECO did not provide its historical residual renewal CAPEX in its revenue application.

Comparison of Recommended and Forecast Residual Renewal CAPEX



Our recommended reductions are discussed below.

- We recommend that CAPEX on vehicle replacements over the period Jan 2009-Jun 2010 be reduced as the expenditure is high compared to the remainder of the forecast period and has not been explained by VECO.
- We recommend that expenditure on a new works and asset management system in RY 2013 be deferred to the third regulatory period. We do not doubt the benefits of such software, which is widely used internationally. However, VECO is also proposing to install new SCADA-EMS software in RY 2013 and we consider that it will be very difficult to effectively implement two major new network-related software applications simultaneously. If the implementation is deferred until the third regulatory period, APC will have time to carefully assess its requirements and include a properly developed and costed proposal in its revenue application for the third regulatory period.
- We recommend that expenditure on consumer metering for the period Jan-Jun 2009 be reduced to the level of expenditure forecast by VECO over the remainder of the forecast period.

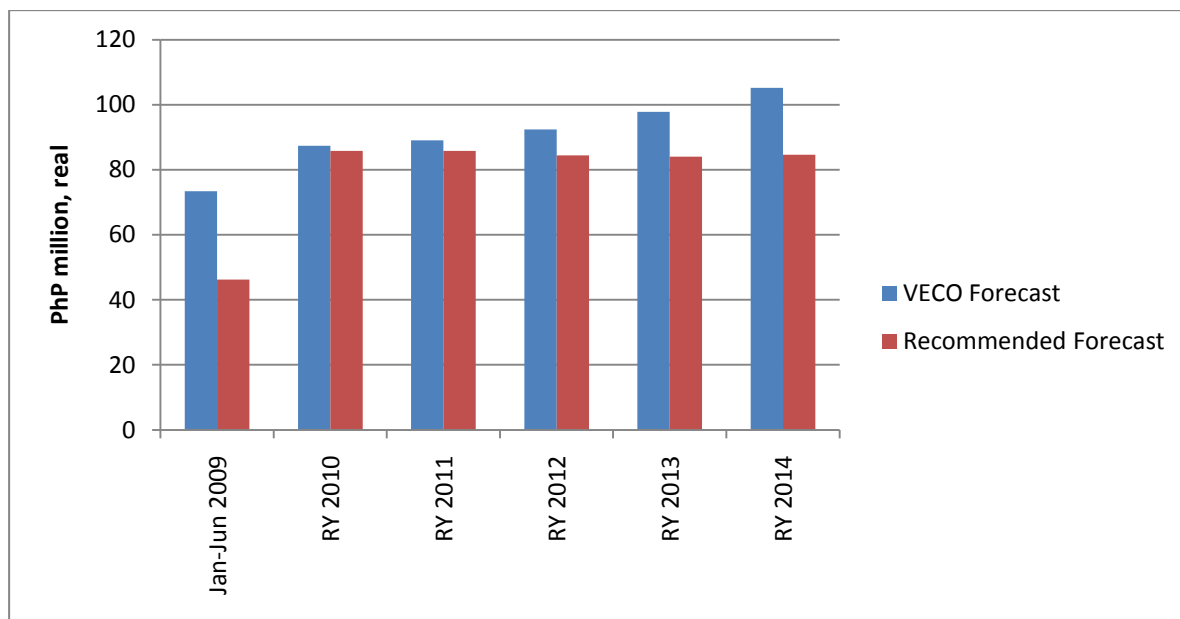
RESIDUAL REFURBISHMENT CAPEX

A comparison of our recommended total residual refurbishment CAPEX with VECO's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of VECO Forecast and Recommended Residual Refurbishment CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
VECO Forecast	73.37	87.34	89.08	92.35	97.85	105.23	384.51
Recommended	46.20	85.84	85.83	84.38	83.99	84.63	338.83
Adjustment	(27.17)	(1.50)	(3.25)	(7.97)	(13.86)	(20.60)	(45.68)
Impact of Adjustment	37%	2%	4%	9%	14%	20%	12%

The recommended and forecast residual refurbishment CAPEX is also shown in the figure below. VECO did not provide its historical residual refurbishment CAPEX in its revenue application.

Comparison of Recommended and Forecast Residual Refurbishment CAPEX

In VECO's forecast, the expenditure on transformers, overhead conductors and devices, streetlights, and consumer metering increased progressively in real terms over the forecast period. Assuming the cost of labor and materials is constant in real terms, we see no reason for this increase and VECO did not provide any explanation. We therefore recommend that the forecast CAPEX on these line items be reduced to reflect the levels of expenditure at the beginning of the forecast period.

In addition, VECO budgeted PhP16.08 Million in Jan-Jun 2009 and PhP1.50 Million in RY 2010 for non-network structures and improvements but has not included CAPEX forecast on this line item in the remaining years of the forecast period. We believe this CAPEX relates to building improvements but no information has been provided, except for PhP1.10 Million expenditure for a covered walk. We recommend that this expenditure, except for the budgeted expenditure on the covered walk, not be approved.

OTHER ISSUES

- We are concerned about inconsistencies in the information provided by VECO to support its CAPEX forecast. In particular, it has used a potential 25 MW load at the APO cement plant to help justify its proposed new 138/69 kV substation when the load was not included in its energy or demand forecast because it was considered unlikely to materialize. We do not consider that it should expect its existing customers to fund reserve capacity for industrial loads that are unlikely to eventuate.
- In another example it included a provision for a new substation in Minglanilla for commissioning in November 2009, and then subsequently disclosed that no site had been identified and it is currently reviewing where to locate the substation. We believe that the commissioning date in VECO's CAPEX forecast is unachievable.
- There is evidence to indicate that VECO could work more constructively with NGCP in the planning and construction of new assets at grid connection points. As a result, outcomes that reduce the long term costs to all customers may not be achieved. Good industry practice requires that transmission and distribution utilities work together to plan the development of assets at a connection point with the prime objective of developing outcomes that minimize the lifetime cost of the assets.

1. INTRODUCTION

The Energy Regulatory Commission (ERC) is currently implementing a performance-based form of regulation (PBR) for investor owned electricity distribution utilities in the Philippines. Under the PBR framework a distribution utility will be subject to a cap on the average price that it may charge for the delivery of distribution wheeling services. This price cap is reset in advance of each four year regulatory period using the building block approach described in the Rules for Setting the Distribution Wheeling Rate (RDWR), which was released by the ERC on December 8 2008¹. It takes the form of a price path that specifies the maximum average price (MAP) that a regulated utility may charge in each year of the regulatory period.

The entry of distribution utilities into the PBR process has been staggered into four entry points and the reset process for the setting of the price cap for the six utilities entering the PBR at the third entry point is currently underway. This process will result in the setting of the price path for each utility for a regulatory period that commences on July 1 2010 and terminates on June 30 2014. This regulatory period is specified in the RDWR as the second regulatory period².

The ERC has published a Position Paper, also dated December 8 2008, which sets out in some detail how the price reset process for the six third entry point utilities will be undertaken³.

An important requirement of this reset process is the review of the capital expenditure forecasts submitted by the utilities in the revenue applications that have been submitted in accordance with the requirements of the RDWR and the Position Paper. Capital expenditure over the second regulatory period will impact the size of the regulated asset base (RAB), which will in turn impact both the return on capital (profit) and return of capital (depreciation). Profit and depreciation form two of the building blocks in the price setting process specified in the RDWR.

Geoff Brown & Associates Ltd (GBA) has been engaged by the ERC to review the capital expenditure forecasts of the utilities that will enter PBR at the third entry point. These are:

- Cabanatuan Electric Corporation (CELCOR);
- Davao Light and Power Company (DLPC);
- Ibaan Electric and Engineering Corporation (IEEC);
- La Union Electric Company (LUECO);
- Tarlac Electric Incorporated (TEI); and
- Visayan Electric Company (VECO).

In accordance with clause 4.12.4 of the RDWR the objective of the review is to determine whether each capital expenditure forecast is:

- based upon the best available prices obtainable from international markets;
- reasonably efficient from a design and implementation point of view;

¹ Rules for Setting Distribution Wheeling Rates for Privately Owned Distribution Utilities Entering Performance Based Regulation (Third Entry Point), Energy Regulatory Commission, December 8 2008.

² No first regulatory period applied to the six utilities entering PBR at the third entry point.

³ Regulatory Reset for the July 2010 to June 2014 Regulatory Period for Privately Owned Distribution Utilities subject to Performance Based Regulation, Position Paper, Energy Regulatory Commission, 8 December 2008.

- likely to support the forecast growth in connections, co-incident peak demand and energy delivered; and
- is sufficient to allow the relevant utility to achieve or exceed the applicable target levels of performance.

This report presents GBA's review of the capital expenditure forecast of VECO. The forecast was submitted to the ERC as part of VECO's revenue and performance incentive scheme application (revenue application), on June 15, 2009.

In undertaking this review, we have relied on the accuracy of the information provided to the ERC by VECO. During the clarificatory meeting process, we queried information that appeared to be incomplete, inconsistent or inaccurate. However, we did not undertake an audit or attempt to verify the information on which we relied. We therefore cannot be held responsible for any conclusions or recommendations based on misleading or inaccurate information provided to us.

2. NETWORK OVERVIEW

2.1 NETWORK DESCRIPTION

VECO is the second largest electricity distribution utility in the Philippines with approximately 296,000 customers and a peak demand of 326 MW. Its franchise area includes the cities of Cebu, Mandaue and Talisay and the municipalities of Lilo-an, Consolacion, Minglanilla, Naga and San Fernando.

Currently VECO takes supply at 69 kV from the four National Grid Corporation of the Philippines (NGCP) substations of Naga, Quiot, Banilad and Mandaue. These substations supply a VECO-owned 69 kV network that supplies 12 zone substations with a total capacity of 495 MVA. These zone substations in turn supply a distribution network that is used to distribute electricity to approximately 17,600 distribution transformers located throughout the franchise area. The distribution transformers are used to convert the electricity to the low voltage that is used to supply the majority of VECO customers.

While the above accurately describes the essence of the VECO network, we noted the following features:

- The standard voltage of the distribution network supplied from the zone substations is 23 kV. However, there is currently a legacy 13.8 kV distribution network supplying part of the downtown Cebu city area that is supplied from a single 33 MVA transformer located at Ermita substation. VECO is currently upgrading this network to 23 kV and, as stated at the evidentiary hearing, this work will be completed in March 2010. It is also installing a second 69/23 kV power transformer at Ermita substation. When this work is completed the 69/13 kV transformer currently at Ermita substation will be removed and the whole distribution network will operate at 23 kV.
- The following major generating plants can inject power directly into the VECO network:
 - The Cebu Private Power Corporation (CPPC) operates a 70 MW diesel power plant that injects power into VECO's 69 kV subtransmission network at the Ermita zone substation.
 - San Miguel Corporation (SMC) operates a 15 MW diesel generator power plant that connects directly into a 69 kV line close to the Mandaue zone substation. We understand that the power plant is primarily used by SMC to supply its own internal load and does not normally inject power into the VECO network. Nevertheless it is synchronized to the network and thus can inject power if it is not required by SMC.
 - The East Asia Utilities Corporation operates a 49.6 MW diesel power plant that can inject power into VECO's 69 kV network at a connection point located at the Mandaue end of the old Mactan bridge.
- VECO has two major consumers, SMC and the Waterfront hotel, that are directly connected to its 69 kV network. While, as noted above, SMC can inject power into the network, it is primarily a consumer. In addition, VECO retails electricity to Cadiz Steel and Cebu Steel, which are directly connected to 69 kV lines that are currently owned by NGCP, although VECO is proposing to purchase both lines during the second regulatory period.
- VECO also has approximately 260 customers that take supply at distribution voltage (23 kV or 13.8 kV). Its remaining customers take supply at low voltage.

- In addition to VECO's four main connections to the NGCP network, it has a connection at Tolo-Tolo to an NGCP owned 69 kV line, which is supplied from NGCP's Compostela substation. The Tolo-Tolo connection point is connected to VECO's Consolacion substation via a 1.5 km 69kV line owned by VECO. While this line is not normally used for power transfer, it is maintained in an energized state and is available as a back-up supply to the Consolacion and Pakna-an substations.

2.2 CURRENT AND FORECAST DEMAND

Growth in peak demand is a key driver of capital expenditure and the forecast growth in demand therefore underpins this review. If, for example, the ERC considers that the peak demand forecast in the revenue application is high, then some of the projects forecast towards the end of the second regulatory period will not be required until after the start of the third regulatory period. VECO's revenue application forecast the network after diversity peak demand to grow from 326.1 MW in 2008 to 384.5 MW in 2014, an increase of 38.5 MW, representing an average growth rate of around 2.7%. Overall, given the inherent uncertainties in forecasting demand, we believe this forecast is reasonable. Our view is that, while the forecast may underestimate the impact of the current economic recession on electricity demand, it may also not fully account for an expected resurgence in demand growth once the recession ends. Hence we think that the expected level of electricity demand at the end of the second regulatory period is a reasonable basis for this capital expenditure review.

On this basis we have assumed the following peak demand forecast as the basis for this review. This forecast, which is taken directly from Tables H2.1.1 and H2.1.2 of VECO's revenue application, is shown in Table 2.1 below.

Table 2.1: Peak Demand Forecast

	2008	2009	2010	2011	2012	2013	2014
MW	326.1	336.5	345.8	355.7	365.2	374.4	384.5
MVA¹	343.3	354.2	364.0	374.4	384.4	394.1	404.7

Note 1: Assuming a power factor of 0.95.

2.3 NETWORK UTILIZATION

The extent to which the existing network is utilized is also relevant to the required capital expenditure since if the network is lightly utilized then some proposed capital expenditure may potentially be deferred until demand growth has used up existing spare capacity.

A network that is heavily utilized will be unreliable since unplanned network faults will generally result in customers being left without supply until the fault is repaired. On the other hand networks that are lightly utilized are economically inefficient since they include excess assets that must be paid for but which are not delivering benefits to customers. Hence determining the appropriate level of network utilization requires reliability to be balanced against economic efficiency. As a first step in this review, we have estimated the network utilization of power transformers and the utilization of the total 23 kV distribution feeder capacity in order to determine the extent to which spare capacity in the existing network can be used to accommodate the forecast growth in demand. We did not estimate the utilization of the 69 kV subtransmission network as the revenue application did not include any significant projects with the objective of increasing this capacity⁴. Our analysis assumes that the upgrade of the 13.8 kV transmission network currently supplied from Ermita is complete and two 69/23 kV transformers supply the Ermita substation.

⁴ The 138 kV project would increase the capacity of the subtransmission network through the additional feeders to be connected to the proposed new substation. However this was not the primary reason for the construction of this substation.

2.3.1 Utilization of Power Transformers

The 69/13.8 kV power transformers currently on the VECO network are shown in Table 2.2.

Table 2.2: Existing Transformer Capacity

Substation	Transformers	Total Capacity (MVA)
Ayala	1 x 33 MVA	33
Banilad	1 x 33 MVA	33
Cabancalan	1 x 33 MVA	33
Calamba	1 x 33 MVA	33
Caretta	2 x 33 MVA	66
Consolacion	1 x 33 MVA	33
Ermita	2 x 33 MVA	66
Mabolo	1 x 33 MVA	33
Mandaue	1 x 33 MVA	33
Naga	1 x 33 MVA	33
Pakna-an	2 x 33 MVA	66
Pardo	1 x 33 MVA	33
Total	15 x 33 MVA	495

Source: SKM Valuation Report. The transformation capacity at Ermita has been updated to reflect the replacement of the 13.8 kV transformer with a 23 kV unit.

As noted above the forecast peak demand at the end of the second regulatory period is 400 MVA. However this includes the following loads that are supplied at 69 kV and therefore do not use this transformer capacity.

Table 2.3: 69 kV Connected Loads

Customer	Load (MW)	Comment
Waterfront Hotel	3	Own transformer supplied from VECO subtransmission network.
Cadiz Steel	0.3	Directly connected to NGCP line
Cebu Steel	0.5	Directly connected to NGCP line

Source: VECO; SKM Valuation Report.

For the purposes of this analysis we have assumed that the maximum 23 kV coincident demand in 2008 was 339 MVA after discounting the 69 kV load component and assuming a power factor of 0.95. For this review we have forecast this to increase to 400 MVA at the end of the second regulatory period. Hence, if no additional transformer capacity is added during the second regulatory period the power transformer utilization will increase from a current 68% to approximately 81% at the end of the second regulatory period.

In its revenue application for entering PBR at the first entry point, MERALCO used 70% power transformer utilization as its planning criterion for the maximum acceptable transformer utilization and this was accepted as reasonable by both PB Associates and the ERC⁵. We think it reasonable to use a planning criterion based on a global analysis of transformer utilization for networks where there is a high level of normally open interconnection between distribution feeders from neighboring substations. For such networks it is possible to optimize the loading of the transformer population by reconfiguring the distribution network. Hence, when a power transformer becomes heavily loaded the utility should first look to reduce the loading on the transformer by

⁵ Review of Forecast Expenditure, Manila Electric Company; PB Associates, February 22 2007, Section 2.3.1, p4.

transferring excess load to other less heavily loaded transformers. Such a reconfiguration may need to extend over a wide area and not necessarily be confined to those substations immediately adjacent to the heavily loaded transformer. We note that in its revenue application VECO has provided no evidence that it has done this.

We also believe that MERALCO's 70% maximum power transformer utilization criterion is appropriate. The 30% unused capacity makes provision for diversity⁶ and for the unplanned loss of a single transformer at times of peak load⁷.

Assuming 400 MVA peak load, a total power transformer capacity of at least 571 MVA is required by the end of the second regulatory period if transformer utilization is to be kept below 70%. We therefore consider that the installation of only three (3) new 25/33 MVA power transformers over the second regulatory period is necessary. This is substantially less than the eight (8) additional transformers VECO is proposing, which would result in the installation of an additional 264 MVA of transformer capacity to supply approximately 61 MVA of additional load⁸.

We note also that VECO has two mobile transformers available for emergency use, but we have not considered these in our analysis, as they take time to install in an emergency. However, the availability of these transformers mitigates the risk of a major transformer failure resulting in an extended outage and also provides a level of comfort should load increase at a significantly higher rate than assumed for this review.

2.3.2 Utilization of the Distribution Network

The analysis of transformer utilization in Section 2.3.1 presupposes that there is sufficient capacity in the distribution network to allow the network to be reconfigured and load to be transferred from one power transformer to another. To confirm this, we have assessed the total capacity of the distribution network (at the connection point of each feeder) and compared this with the required level of load transfer.

All VECO's 23 kV feeder backbone lines use 336.4 MCM aluminum core steel reinforced (ACSR) conductor, which has a thermal capacity of 21 MVA. VECO has, on average, 2.4 feeders per power transformer⁹, which gives an average feeder capacity of 50.4 MVA for each 33 MVA power transformer. If it is assumed that each transformer is, on average, 70% utilized then the distribution network utilization is 46%¹⁰. This provides ample capacity for optimizing the load on each transformer and for transferring load within the distribution network. We note that the zone substations are located relatively close together¹¹ and, given the distribution voltage of 23 kV, the constraint on feeder rating is likely to be thermal rather than voltage¹².

2.3.3 Timing of Transformer Installations

In Section 2.3.1 we established that VECO would need three (3) additional power transformers to be installed by the end of the second regulatory period. In this section we forecast when these transformers will be required.

Table 2.2 shows that the total power transformer capacity is currently 495 MVA. Assuming 70% overall power transformer utilization, this will support a total 23 kV peak demand of 346.5 MVA. Each additional transformer will support an increase in peak

⁶ A diversity provision is needed because the load individual transformer peak loads will occur at different times.

⁷ Under Table 5.1 of the Position Paper a level of security of the subtransmission system of n-1 is permitted. This means that utility should be able, after network reconfiguration, to supply all customers using existing assets following the loss of supply of a single power transformer at peak load.

⁸ VECO's CAPEX forecast provides for the installation of a total of 9 transformers. However we have excluded the Ermita TR2 project from this analysis as it replaces existing capacity.

⁹ Table 4-6 of the SKM valuation report shows a total of 36 feeders, which are currently supplied by 15 power transformers, each rated at 33 MVA.

¹⁰ Utilization = transformer rating x 70% / total feeder rating = 33 x 0.7 / 50.4 = 46%.

¹¹ Currently there are 12 zone substations within a total supply area of 670 km².

¹² Where feeders are very long, they may not be able to be loaded to their full thermal rating if customers at the end of the feeder are to receive an acceptable voltage. We do not think this constraint would apply in VECO's case.

demand of 23.1 MVA based on an ONAF rating of 33 MVA and a utilization of 70%. On this basis the peak demands that will trigger the installation of the three additional transformers are shown in Table 2.4.

Table 2.4: Trigger Points (MVA) for Additional Power Transformer Capacity

Transformer	Peak Demand Trigger
1	346.5
2	369.6
3	392.7

Our analysis of the timing of the installation of the additional power transformers is shown in Table 2.5. This analysis assumes that the only load supplied at 69 kV and thus not utilizing VECO's power transformers is Cebu Steel and the Waterfront Hotel, given that the SKM Valuation Report recommended that the supply to Cadiz Steel be optimized to 23 kV.

Table 2.5: Timing of Power Transformer Installations

	2008	2009	2010	2011	2012	2013	2014
System peak demand (MVA)	343.3	354.2	364.0	374.4	384.4	394.1	404.5
Waterfront Hotel and Cebu Steel (MVA)	3.7	3.7	3.7	3.7	3.7	3.7	3.7
23 KV Peak Demand (MVA)	339.6	350.5	360.3	370.7	380.7	390.4	400.8
Timing		T1		T2		T3	

VECO is currently proposing to install two new power transformers (Camputhaw and NRA) in June 2009 and a new power transformer at Minglanilla in November 2009. This is in addition to the new power transformer at Ermita which is required to replace existing 69/13.8 kV transformer capacity. The analysis in Table 2.5 indicates that installation of two of these power transformers can be deferred.

We have not reviewed the prioritization of the new transformer installations proposed by VECO, given the available distribution network capacity and the relatively compact network installation, and have relied on the prioritization indicated by VECO. On this basis we have assumed that the Camputhaw¹³ transformer should be installed by June 2009, the NRA transformer can be deferred to RY 2011. Based on the commissioning dates proposed by VECO the next highest priority transformer would be Minglanilla. This substation is discussed in Section 4.10 and is not recommended for construction. We have therefore assumed that the Mandaue TR2 transformer, proposed for commissioning in October 2010, be installed in RY 2013. Notwithstanding this, we consider that VECO should be free to reprioritize the location of its power transformer installations within the allowed capital expenditure budget.

¹³ As noted in Section 3, VECO applied for regulatory approval of the capital expenditure for the Camputhaw transformer in 2006 and for the NRA transformer in 2008. We therefore assume that Camputhaw has the higher priority.

3. OVERVIEW OF HISTORICAL AND FORECAST EXPENDITURE

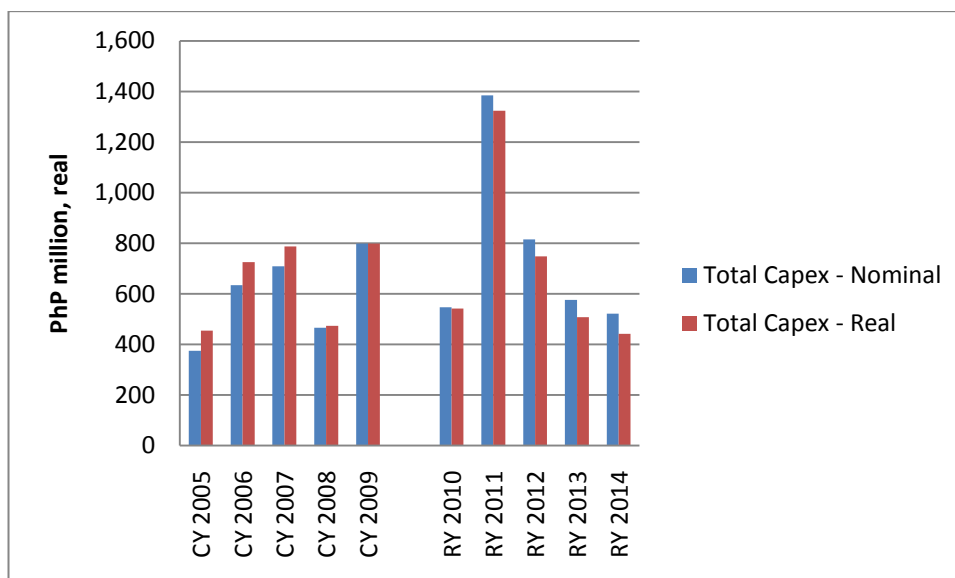
VECO’s historical and forecast total CAPEX, as presented in its revenue application, is shown in Table 3.1 below.

Table 3.1: Total Historical and Forecast CAPEX (PhP Million)

	Historical (Calendar Year)					Forecast (Regulatory Year)				
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PhP nominal	375.46	634.23	708.49	465.53	799.24	546.76	1,384.06	815.13	575.48	521.13
PhP real	455.05	724.64	787.57	473.01	799.24	541.63	1,323.46	748.02	507.78	442.15

This CAPEX is shown graphically in Figure 3.1 below.

Figure 3.1: Total Historical and Forecast CAPEX (PhP Million)



An examination of the above information indicates that the base year for conversion from real to nominal PhP is CY 2009, where real and nominal expenditures are identical. For prior years nominal expenditure is less than the same expenditure expressed in real terms while in subsequent years the reverse applies. This is to be expected in situations where the real value of the PhP depreciates over time. In this report all expenditures are expressed and PhP real, 2009 unless otherwise stated in order to remove the impact of the time value of money from our analysis.

For VECO and all third entry point utilities the regulatory year starts on 1 July and finishes on 30 June. RY 2010 denotes the regulatory year ending 30 June 2010. Hence there is a six (6) month overlap between CY 2009 and RY 2010 and expenditure budgeted to occur during this overlap period (1 July 2009 – 31 December 2009) is shown twice in the above forecast. This is a consequence of the ERC’s transition from calendar years to regulatory years for regulatory forecasting and rate setting purposes.

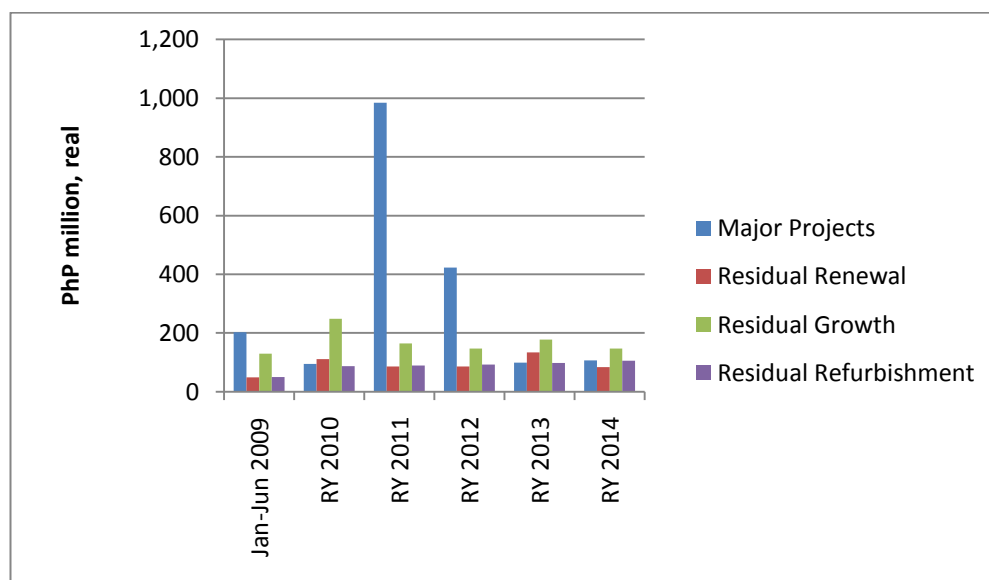
It can also be seen that, in real terms, budgeted and forecast CAPEX is highest in CY 2009, RY 2012 and RY 2013. This high capital expenditure is due to the impact of major projects being proposed for commissioning over these periods. VECO is proposing to commission four new power transformers by 31 December 2009 and in RY 2011 and RY 2012 it is proposing to commission two new 138 kV transmission lines and a 138 kV substation in order to import electricity from a new coal fired power plant to be constructed by the Cebu Energy Development Corporation (CEDC).

The impact of these major projects on VECO’s forecast is shown in Table 3.2 and Figure 3.2 below, where VECO’s forecast expenditure is broken down into the ERC’s major CAPEX categories. In preparing this table we have shown the forecast CAPEX for Jan-Jun 2009, rather than for the full CY 2009, in order to avoid showing the expenditure during the Jul-Dec 2009 overlap period twice. VECO was unable to provide a breakdown for its historical expenditure over the years CY 2005-08.

Table 3.2: Breakdown of Historical and Forecast Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Major Projects	202.56	94.84	984.11	422.95	98.62	106.27
Renewal	49.23	111.17	86.02	85.99	133.52	84.08
Growth	129.75	248.28	164.24	146.73	177.79	146.57
Refurbishment	49.54	87.34	89.08	92.35	97.85	105.23

Figure 3.2: Breakdown of Historical and Forecast Expenditure (PhP Million, real)



Clearly, the major projects forecast in RY 2011 and RY 2012 have a major impact on VECO’s overall CAPEX requirement and we have carefully examined the need for these projects during this review. We have not allowed the possibility that major projects scheduled for completion over the period Jan-Jun2009 may already be in service at the time of undertaking this review to influence our approach and have examined each of these major projects on their merits.

ERC has advised that the only major projects for which VECO already has regulatory approval are the Camputhaw substation¹⁴ and the North Reclamation Area (NRA) substation¹⁵ both of which are due for commissioning by 30 June 2009.

¹⁴ ERC Case No 2006-083RC. Note that this substation is described as Lahug in the ERC case but the project has been relocated to Camputhaw as DLPC was unable to buy land in Lahug.
¹⁵ ERC Case No 2008-085MC. Note that the forecast cost for the ERC case was PhP63.72 million.

4. MAJOR PROJECT EXPENDITURE

4.1 138 KV PROJECT

This project includes the construction of a 37 km 138 kV line between a new 246 MW coal-fired plant being constructed by the Cebu Energy Development Corporation (CEDC) in Torledo City and a new 100 MVA, 138/69 kV substation to be constructed under the project by VECO in Colon, within the municipality of Naga. The estimated cost of this project, as submitted in the revenue application, is PhP870 Million and commissioning is planned for July 2010.

Given the very high cost, very little justification of the need for the project was provided in the revenue application. We therefore asked VECO to provide a presentation on the project at the clarificatory meeting held in Cebu on 12 August 2009. This presentation forms part of the records of this case and the analysis in this section is largely based on the information provided therein.

The Visayas is currently facing a power generation shortage and all distribution utilities fed from the NGCP Visayas grid, including VECO, are facing power rationing at times when sufficient generation to supply the load is not available. As a result, VECO consumers have experienced interruptions to their power supply. VECO and other Visayan distribution utilities have load shedding arrangements in place to manage this situation and to maintain the integrity of the power system when faced with generation shortages.

VECO's current power supply agreement with the National Power Corporation (NPC) expires in 2010 and it is in the process of negotiating new power supply agreements with NPC and private sector generators to secure the electrical energy needed to meet its requirements following the expiry of this supply agreement. To this end on July 31 2009 it signed a Memorandum of Agreement (MOA) with CEDC to prepare an Electric Power Purchase Agreement (EPPA) whereby VECO will agree to purchase power from CEDC on mutually agreed terms and conditions. Before any such EPPA becomes effective, it will need the approval of ERC.

As a basis for our CAPEX review, given the shortage of generation in the Visayas, we accept that the new CEDC power station is required and that there is a need for adequate transmission capacity to transport this electricity between the new power station and the VECO network. We also assume that VECO and CEDC will be able to negotiate a mutually acceptable EPPA and that this will receive ERC approval.

We have reviewed the information provided by VECO on the capacity of the existing transmission network and are satisfied that a new 138 kV transmission line is needed to deliver the full capacity of the new plant to its contracted customers. We understand that NGCP has indicated that is not in a position to construct this new line in time for the commissioning of the new plant but that it has still to formally waive the right it has under its franchise to build the line. One problem that NGCP faces is that the proposed line was not an approved project under the revenue cap set by the ERC for its second regulatory period under PBR.

4.1.1 VECO Proposal

VECO proposes to construct the new transmission line itself and connect it directly to its distribution system, bypassing the NGCP network in order to avoid NGCP power delivery charges. The project includes the construction of the line and also the construction of a new 100 MVA, 138/69 kV substation at Colon to inject the power into VECO's subtransmission network. It has identified a suitable line route and obtained the planning consents required for construction to commence.

Because of the relatively low load in the Naga area, this project alone will not enable VECO to accept the 105 MW capacity it expects to contract from the CEDC plant. It has therefore proposed in its PBR CAPEX forecast the construction of a second 138 kV line between the new Colon substation and Quiot. This project, which is discussed in Section 4.11, will increase the estimated cost of the new assets to accept power from the CEDC plant to PhP1,203 Million.

The design of the new 138 kV line to be constructed under this project appears reasonable. The only relevant issue is the optimal size of conductor. VECO is proposing to construct a single circuit line using twin 795 MCM conductor. The issue is whether it would be better to construct the line using single 795 MCM conductor, given that a single conductor line would have a rating of 216 MVA when energized at 138 kV, more than twice the required capacity. However VECO has undertaken a technical and economic study which has shown that, given the load and line length required, twin 795 MCM conductor is the most economic and technically efficient solution. The reasons for this are:

- the voltage drop of the single conductor solution would be excessive given the total length of line the power transfer required.
- the incremental cost of the twin conductor solution is only 11%, while losses would be reduced by 50%. The VECO analysis indicates that the annual savings in the cost of losses using the twin conductor line is almost 2.5 times the additional cost of the higher capacity line, based on the likely peak load transfer.
- the higher capacity line would provide scope for VECO to increase the amount of energy that it purchased from CEDC in future. It has stated that it is possible that additional power generation capacity could be constructed on the power station site.

VECO’s proposal to design the project to bypass the NGCP grid is based on an economic analysis that shows it would be more expensive to use NGCP assets to deliver the power than to deliver the power using its own new specially constructed assets. We have confirmed this through the indicative economic analysis presented below.

NGCP Grid Bypass

The annualized cost of the proposed project can be estimated using the PBR building block approach to calculate the annual revenue requirement to service the cost of the new assets required to deliver the power. Using the PBR building blocks, the annual revenue requirement would be the sum of (i) the return on capital, (ii) the return of capital (depreciation) and (iii) maintenance costs. We have estimated each of these building blocks below.

In our analysis we assumed a weighted average cost of capital (WACC) of 16.27%, as used in VECO’s revenue application and we assumed maintenance costs to be 1% of the capital cost, as assumed by VECO in its presentation. For simplicity we have assumed an asset life of 30 years for all assets in calculating depreciation. The capital cost of the project was taken to be PhP1,203 Million, as forecast by VECO.

Using these parameters, each of the building block costs is calculated below.

Return on Capital	=	Project cost x WACC
	=	PhP1,203 Million x 16.27%
	=	PhP195.7 Million
Return of Capital	=	Project cost /asset life

	=	PhP1,203 Million / 30 years
	=	PhP40.1 Million
Maintenance	=	PhP1,203 Million x1%
	=	PhP12.0 Million

The annualized cost of the project, which would be passed on by VECO to its customers through the distribution wheeling rate is the sum of these individual building block costs or **PhP247.8 Million**.

Power Delivery by NGCP

In NGCP's power delivery charges we used an assumed power delivery charge for the Visayas grid of PhP282.25 per kW per month. This figure is taken from the assumed rate in the ERC decision dated December 15 2008 on Case No 2008-056 RC. We have assumed that power will be available from the CEDC plant for only 11 months of the year as the plant will not have 100% availability.

Transmission charge	=	PhP282.25 x 105,000 kW x 11 months
	=	PhP323.6 Million per annum.

Conclusions:

Based on the assumptions of this analysis there would be an annual saving to VECO customers of PhP75 Million if VECO is allowed to construct a bypass network.

Under the building block approach to the pricing of transmission and distribution services, the revenue to be recovered through the wheeling rate is driven by the cost of the asset. If the cost an asset increases then the annualized cost that a utility is entitled to charge for the use of the asset will also increase. Notwithstanding this, VECO is able to argue that its customers will pay less for a complete bypass of the NGCP grid, when the cost of the additional assets required is PhP1,203 Million, than they would if existing NGCP capacity was used, where the cost of the additional assets required is only PhP464 Million¹⁶. This would seem counter-intuitive for an economic analysis based on building block principles.

This situation arises because of the averaging effect of the "postage stamp" pricing mechanism used for transmission pricing. Under this approach all customers taking supply off the Visayas grid pay the same rate for energy delivery, irrespective of their location on the grid or the distance over which the power is transported. This rate is determined by the total value of all Visayas grid assets.

If VECO is allowed to bypass the grid, there will be a loss of revenue to NGCP and this will have to be made up by all grid users, (as NGCP is entitled to earn predetermined allowed revenue). Hence if VECO's proposal is allowed to proceed, the total wheeling costs paid by all grid users will actually be higher than if NGCP assets were used where capacity is available. Thus, if the VECO bypass proposal is allowed, while VECO customers will pay less, other grid users not affected by the project will pay more and the total costs paid by all grid users will be higher.

4.1.2 Engineering Considerations

If NGCP assets were used to deliver the power, the new 138 kV line that VECO proposes to construct under the project would still be required as the existing transmission grid has

¹⁶ There may be additional costs in providing for the additional connection at the NGPC Naga substation, particularly if a new termination bay has to be constructed. We have insufficient information to assess these costs but they are unlikely to change the conclusions of this analysis.

insufficient capacity to evacuate all the power the CEDC plant will produce. However the line would be terminated on the existing 138 kV bus at NGCP's Naga substation, which we understand is located very close to the site of VECO's proposed new substation at Colon. The additional assets proposed by VECO to fully bypass the network would not be required as NGCP's existing 138/69 kV transformers at Naga would perform the function of the transformer at VECO's proposed new Colon substation and NGCP's 138 kV Quiot-Naga line would be used instead of the second line to transfer the power VECO is unable to absorb at its proposed Colon substation to the Quiot point of injection.

From a technical perspective there are advantages in using NGCP assets to deliver the power from the CEDC plant to the VECO subtransmission grid. In particular:

- it will likely improve the power transfer capacity of the Visayas transmission backbone by providing an additional point of reactive power injection into the backbone line; and
- it will reduce transmission losses as the power transfer between Naga and Quiot is counter to the normal power flow on this line, which is from Leyte to Negros.

Conclusions:

We conclude that the use of existing NGCP assets is better option from a technical perspective.

4.1.3 Loading on Proposed 138/69 kV Substation

During the clarificatory meeting, VECO stated that its proposed new 100 MVA 138/69 kV substation would be used to supply the load on the following four 69/23 kV substations.

- CEMEX 25.0 MW
- Naga 9.0 MW
- Minglanilla 14.5 MW
- Pardo 14.5 MW

We were unable to reconcile this statement with the information provided in the revenue application because the 25 MW CEMEX load was not included in the energy or demand forecasts provided in Schedule H. Further, the supply of Minglanilla and Pardo from the new substation at Colon would require the construction of a 69 kV line between the new Colon substation and the existing 69/23 kV substation at Pardo. This line was not shown on VECO's subtransmission single line diagram and there was no provision for the construction of such a line in the CAPEX forecast. We therefore asked the ERC to issue an order requiring VECO to clarify these issues.

In response VECO advised that CEMEX is the owner of an existing APO cement manufacturing plant, which is not currently connected to either the NGCP or the VECO network. It has a peak electricity demand of approximately 40 MW, which is supplied from its own internal 66 MW power plant. In August 2008, APO signed a contract to purchase power from VECO and which was approved by the ERC on November 24, 2008¹⁷. This contract was signed at a time when the world price of oil was steadily rising. Now that the price of oil has fallen again, APO no longer plans to purchase power and VECO has agreed to waive the contract. VECO therefore considers that the load should not be included in the energy forecast since it is unlikely to materialize during the forecast period.

¹⁷ ERC Case No 2008-085MC.

On September 9 2009, (after the submission of its revenue application and the commencement of this review) VECO signed a contract to buy power from APO. To implement this it needs to construct a 3.3 km, 69 kV line and a 25 MVA substation that will connect the APO plant to the 69 kV bus of VECO's existing Naga 69/23 kV substation. This line, which we consider a distribution connection asset, has not been included in the CAPEX forecast and will be constructed using VECO's "internally generated funds".

In respect of the 69 kV line between Naga and Pardo, VECO advised that it is an approved CAPEX project¹⁸. Construction was delayed by right of way issues but is now in progress and commissioning is expected by the last quarter of 2009. The project was inadvertently omitted from VECO's revenue application.

Conclusions:

We agree with VECO's conclusion that the 25 MW APO cement plant load should not be included in the load forecast. However, we find VECO's approach to this potential load inconsistent, as its existence is used as a strong argument to justify the construction of the new Colon substation. We consider that VECO cannot have it both ways.

Without the APO load the case for constructing the new substation at Colon is substantially weaker as the other loads to be supplied from this substation can be supplied using VECO's existing assets. Assuming that a VECO-owned bypass was to be used, it is likely that around 90 MW of contracted CEDC power could be delivered to the Quiot substation through a direct 138 kV line between the power station and Quiot. The constraint is the rating of the existing transformer at Quiot and if absorption of the full 105 MW of contracted capacity was required a second transformer would be needed. However it would be more cost effective to install this at Quiot as this would avoid the infrastructure costs associated with the proposed new green field site at Colon.

In respect of the 69 kV line between Colon and Pardo, the analysis in Section 4.6 of this report indicates that this line is not required to supply the expected loads through to the end of the second regulatory period under an n-1, contingency, provided it is assumed that output from the 70 MW CPPC power station (which feeds into the Ermita bus) was available. The main issue is supply of the load currently connected to the Pardo substation in the event of the loss of the Quiot-Pardo subtransmission line. Under such a contingency it could be difficult to supply this load without the CPPC power station in service. However, we believe that an assumption that reasonable levels of embedded generation are available is justified when undertaking n-1 contingency studies.

The 69 kV line will become necessary once VECO starts buying power from the APO cement plant as the line will be used to transmit this power to Pardo and Ermita. However, as embedded generation at APO was not included in the revenue application, we have not explicitly considered it in this review.

4.1.4 Recommendations

Notwithstanding VECO's economic argument, we do not recommend the approval of the full project cost as proposed by VECO, given that its proposed bypass solution is sub-optimal from a technical perspective and that that total cost to all grid users is greater than if available NGCP assets were utilized. Furthermore, we do not recommend that the proposed new substation at Colon proceed as the case for this depends (in our view) on the existence of the APO cement works load, which VECO itself considers unlikely to materialize.

We acknowledge that VECO has already completed the design of the 138 kV line between the CEDC power station and Naga and obtained the required planning approvals. It is unlikely that NGCP would be able to construct a line in time to meet the

¹⁸ ERC Case No 2006-163RC.

proposed commissioning date of the power station without relying on work already completed by VECO. Given this, we consider that a workable solution would be:

- VECO be allowed to proceed with the construction of the 138 kV line between the CEDC power station and Naga but with the terminated at the NGCP Naga substation rather than at a new VECO substation located nearby. Once commissioned, the line should be included in VECO's fixed asset register. This would allow VECO to recover the cost of the line from its customers and to earn a reasonable return on its investment. It will also avoid the need the proposed new 138 kV line to the Quiot substation, as delivery of the power to Quiot can be performed by existing NGCP assets. Given that we do not recommend that the Colon substation proceed, this proposal would allow VECO to accept the full contracted output from the CEDC plant as soon as the new CEDC-Naga line is completed.
- VECO leases the new 138 kV line to NGCP, which operates it as an integral component of the transmission network. Economically the amount to be paid by NGCP for this lease should be determined through a quantitative analysis of the benefits of the line to NGCP, which would include the value of the additional reactive power injection to the operation of the network and the reduction in losses. The reduction in losses would result not only from the reduced current flow on the existing NGCP line between Naga and Quiot (as discussed in Section 4.1.2) but also from the NGCP's use of the high capacity VECO line to deliver power generated from the CEDC plant to other grid users.

However we favor a more pragmatic approach where it is agreed that the payment for the lease is to be equal to the delivery charges that VECO would normally be expected to pay NGCP for the use of its assets to deliver the power purchased from CEDC to the VECO network. In other words, in return for the use of the line, NGCP does not charge VECO for the delivery of power sourced from the CEDC plant. This removes the potential double charging, which forms the basis of VECO's justification for bypassing the NGCP grid.

Our recommendation is based on this outcome and we have adjusted VECO's CAPEX forecast for the second regulatory period to remove the forecast cost of the proposed new substation from the 138 kV project. Our recommended adjustment does not take into account any costs that may be incurred by NGCP in providing for the termination of the new line at its Naga substation. We have no information on the magnitude of these costs, which could potentially involve the extension of the substation by a breaker-and-a-half switchgear diameter. We envisage that any such costs would be quantified during negotiations between VECO and NGCP and consider that the new assets within NGCP's Naga substation switchyard should be constructed and owned by NGCP. The cost of these assets could be provided for in determining NGCP's required revenue for the third regulatory period.

During the clarificatory meeting, VECO stated that the forecast cost of the 138 kV line as submitted in its revenue application was insufficient and that it intended to manifest for additional costs for this project. It agreed to provide additional information to support this manifestation to increase the cost, including quotations showing the basis for the increased materials cost on which the revised cost estimate was based. Following the clarificatory meeting VECO submitted the revised forecast as shown in Table 4.1.

Table 4.1: Revised Forecast for 138 kV Project Cost (PhP Million real)

	Revenue Application	Revised
Line	463.93	558.35
Substation	406.05	304.72
Total	869.98	863.07

It can be seen from Table 3.1 that the revised forecast increases estimated cost of the line by more than 20%. However this is offset by a 25% reduction in the proposed substation to reduce the overall project cost by less than 1%. In its final order, the ERC requested VECO to provide additional information on the reason for the reduction in the cost of the proposed substation and in response VECO advised that it had decided to transfer one of the 100 MVA transformers currently at Banilad, and which it had recently purchased from NGCP, to the proposed Colon substation.

The line cost increases were generally spread across expenditure components and included PhP7.88 Million new expenditure for *VECO expenses* and *project management*. The revised forecast, if accepted, would materially reduce the level of our recommended project adjustment, given that the adjustment removes the cost of the substation but not the line. However we are not inclined to accept the revised forecast at this point, given that VECO has provided no information to support the change. We also asked Asian Appraisal to provide an independent assessment of the cost of this line and were advised that a fair estimate was PhP445.56 Million, which indicates that VECO's original cost estimate was not unreasonable.

We also believe that, as a matter of principle, the regulator and its consultants should be able to rely on forecasts in the revenue application when undertaking an expenditure review and the upwards adjustments to these forecasts should be allowed only in exceptional circumstances. We note also that this project is due for implementation in RY 2011 and that the ERC regulatory model already makes an adjustment of 4.6% (based on VECO's assumed economic indicators) to account for cost inflation.

Our recommended adjustment for this project is therefore shown in Table 4.2 below.

Table 4.2: Adjustments to Cost of 138 kV Project (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast			869.98			
Adjustment for deletion of substation			(406.05)			

This recommendation is based on the information that has been made available to us by VECO for the purposes of this expenditure review and assumes that VECO and NGCP negotiate a project outcome along the lines described above. We would expect that these negotiations would be completed and their outcome reported to ERC in time for the final determination. We would also expect that, by that time, VECO would have completed a power purchase contract with CEDC and submitted it to the ERC for approval. We acknowledge that it may be appropriate for us to revise our recommendation at that point in order to take account any new information that is available at the time the ERC prepares its final determination.

Finally we note that, should VECO construct a 138 kV line to bypass the NGCP grid and connect the CEDC power station to its subtransmission network it would be a radial line used only for this purpose and would meet the criteria for classification as a distribution connection asset. We have not explored the implications of this given that our recommended approach is to operate the line as an integral part of the shared transmission grid.

4.2 BANILAD TRANSFORMER 2

The new transformer has a forecast installed cost of PhP29.91 Million and is scheduled for commissioning in June 2014. Consistent with the discussion in Section 2.3.1 we recommend that the project not proceed during the second regulatory period.

This adjustment to VECO's expenditure forecast is shown in Table 4.3:

Table 4.3: Adjustments to Cost of Banilad TR2 (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast						29.91
Adjustment for deletion of Banilad TR2						(29.91)

4.3 BANILAD-COTCOT 69 KV SUBTRANSMISSION ASSET ACQUISITION

VECO has requested a provision of PhP8.0 Million to fund the purchase of the 9 km section of the 15.74 km Banilad-Compostela 69 kV line that is within VECO's franchise area. The PhP8.0 Million purchase price of the line is assessed by pro-rating the sound value of PhP14.18 Million, as assessed by TransCo on the basis of the portion of the total length that is in the VECO franchise area. The project sheet indicates that the transaction is estimated to be effective in June 2012.

We have the following comments based on our review of the information provided by VECO.

- While the line is called the Banilad-Compostela line the VECO single line diagram indicates that it is no longer terminated at NGCP's Banilad substation. According to the VECO subtransmission single line diagram it is now operated as a radial supply from Compostela to feed Cadiz Steel, which is a VECO customer with a load of about 300 kW.
- The line also supplies CEBECO II, presumably through an upstream tap outside the VECO franchise area.
- There is a tapping point at Tolo-Tolo, which can be used to provide a standby supply to VECO's Consolacion substation. However the VECO owned line between the tapping point and the substation is operated normally open at the Consolacion substation and is used only as a backup supply.
- It would be possible to back feed the Cotcot line through the Tolo-Tolo tapping point to supply CEBECO II should the supply from Compostela substation not be available. In this event, the supply would now originate from NGCP's newer Mandaue substation and require the use of VECO assets to transport the power to the Tolo-Tolo tapping point. Given that the Cotcot line no longer directly interconnects two NCGCP substations we believe that it now meets the ERC criteria for a subtransmission asset and should therefore be made available by NGCP for purchase by the qualified distribution utilities¹⁹.
- Notwithstanding this, we asked VECO to comment on whether it was permitted under EPIRA to purchase the line given that it could also be used to supply CEBECO II. It stated that the two utilities have agreed to separately purchase the sections of the line within their own franchise area, but did not provide any evidence of this agreement. However we consider that CEBECO II will not be disadvantaged in any way by VECO's proposed purchase as it already must rely on the use of VECO assets to provide a backup supply should the normal supply from NGCP's Compostela substation not be available.
- The proposed purchase price is based on the sound value of the line as assessed by TransCo rather than on the SKM valuation. We have no information on the SKM valuation but note that in the case of the Naga- Sibonga line

¹⁹ In accordance with the ERC's *Guidelines to the Sale and Transfer of the TransCo's Subtransmission Assets and the Franchising of Qualified Consortiums*, Energy Regulatory Commission, October 17 2003 an asset is categorised as subtransmission if it directly connect an end-user or group of end-users to the Grid and is exclusively dedicated to the service of that End-User or group of end-users.

discussed in Section 4.12 below the SKM valuation was over 25% lower than the TransCo assessed sound value. We have not pursued this or recommended an adjustment to correct the issue because any adjustment is unlikely to be material to the total CAPEX forecast.

- There are discrepancies in the information provided by VECO as to the length of line to be purchased. VECO originally indicated that the line length was only 1 km but subsequently provided a revised major project information summary that amended the length to 9 km. However this revised summary also indicated that only the length of line between the Cadiz Steel and Tolo-Tolo tapping points is affected by the purchase. After reference to the map VECO provided, we believe that the distance between the two tapping points is only 1 km but that the total length of line within the VECO franchise area is 9 km.
- In its valuation report SKM optimized the supply to Cadiz Steel down to 23 kV. Hence the 1 km section of line between the two tapping points, which is used only to supply Cadiz Steel, serves no useful purpose in the optimized network, and we recommend that the forecast capital expenditure be reduced to remove the provision for the purchase of this line section. The remaining 8 km of line functions as the backup supply to VECO's Consolacion and Pakna-an substations and the purchase of this section of line is therefore justified.
- VECO has not included any provision for this purchase in the line item *transferred subtransmission assets* in the CAPEX template submitted with its revenue application. We understand that the provision has been incorrectly recorded in the *poles, towers and fixtures* and *overhead conductors and devices* line items.
- VECO has advised that it sent a letter to TransCo last April 2008 expressing interest in purchasing the line but had not received a reply as of July 2009. We think VECO should have been more proactive in following this up.

On the basis that there appears to be no impediment to the purchase of this line from NGCP, we recommend that provision for the purchase be allowed. We further recommend that the amount requested by VECO be reduced to remove the cost of the line section between the Tolo-Tolo and Cadiz tapping points, as this section of line is not required to supply the network as optimized by SKM. We have assessed this reduction as PhP0.89 Million, based on the length of this line section relative to the total length of line to be purchased. The impact of this reduction is shown in Table 4.4 below.

Table 4.4: Adjustments to Cost of the Cotcot 69 kV Line Purchase (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast				8.00		
Adjustment for deletion of line section				(0.89)		

We note that no contract has been signed with NGCP for the purchase of this line and that the purchase has therefore not been formally approved by ERC. In particular the purchase price may be affected by the regulatory valuation of NGCP assets recently undertaken by SKM in preparation for the pending reset of NGCP's revenue requirement. We therefore suggest that the final determination include a provision for any difference between the final purchase price and the purchase price assumed for this expenditure review to be recovered by way of an asset specific adjustment when VECO's distribution rate is reset prior to the commencement of the third regulatory period. Such a provision would ensure that the inclusion of expenditure for the purchase of this line would not pre-empt a later decision by the ERC as to whether or not it should approve the purchase contract.

4.4 CALAMBA TRANSFORMER 2

The new transformer has a forecast installed cost of PhP97.52 Million and is scheduled for commissioning in November 2011. Consistent with the discussion in Section 2.3.1 we recommend that the project not proceed during the second regulatory period.

This adjustment to VECO's expenditure forecast is shown in Table 4.5:

Table 4.5: Adjustments to Cost of Calamba TR2 (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast				97.52		
Adjustment for deletion of Calamba TR2				(97.52)		

4.5 CAMPUTHAW SUBSTATION

VECO is proposing to construct a new substation at Camputhaw at a forecast cost of PhP96.34 Million. This substation was due for commissioning in June 2009.

Our analysis in Section 2.3.3 indicates that this new substation is justified and that its timing is appropriate. We recommend no adjustment to VECO's budgeted capital expenditure in respect of this project.

4.6 ERMITA 69 KV SWITCHYARD

VECO is proposing to construct a four (4) diameter, breaker-and-a-half 69 kV switching station at the Ermita substation at a forecast cost of PhP83.64 Million. The forecast commissioning date is November 2010.

The effect of this project would be to convert the existing single bus configuration at Ermita to a double bus arrangement. VECO argues that this would provide greater operating flexibility and higher reliability, particularly after completion of its proposed 138 kV project, when incoming power from both the new CEDC plant and the existing CPPC generator will both feed into the same 69 kV bus at Ermita. As we understand VECO's argument, it is claiming that reliability will be improved by the project as the two important sources of generation can be configured to feed different bus bars.

Unlike most other major CAPEX projects proposed by VECO, this project is primarily driven by reliability rather than growth. The need for the project must therefore be assessed in accordance with the requirements of Table 5.1 of the Position Paper which provides that the subtransmission network and substations may be designed to a quality level of n-1. We interpret this to mean that a project designed purely to improve network reliability should not be recommended if the network in its existing configuration is able to provide a level security of n-1, assuming the most severe single element outage at peak load. In making this assessment we consider it appropriate to be able to call on all sources of generation embedded in the network to the extent they are likely to be available.

Currently, as shown in Figure 4.1, the Ermita substation is normally energized through VECO's 69 kV line 1 but it can also be energized through Line 2. Both lines utilize 795 MCM conductor with a rating of 108 MVA and run in parallel between NGCP's Banilad substation and VECO's Ermita 69 kV substation. The network is currently operated as two radial feeders supplied from Banilad. Backup injection points from the grid are available from the NGCP Quiot and Mandaue substations but these are not used during normal operation. Additional injection is available from embedded generators

operated by the Cebu Private Power Corporation (CPPC) and East Asia Utilities Corporation (EAUC)²⁰.

We have assumed the loads shown in Table 4.6 below for this analysis. These loads have been derived by escalating the actual 2008 substation loads by the overall growth rate of 2.7%. We did not use the forecast RY 2014 substation loads provided to us by VECO as these implied a growth rate of 3.5% which we considered materially higher than the overall growth rate submitted in the revenue application. The load on the Waterfront hotel was taken from the SKM Valuation Report and was assumed not to escalate over time.

Figure 4.1: Normal Operating Configuration of VECO Lines 1 & 2

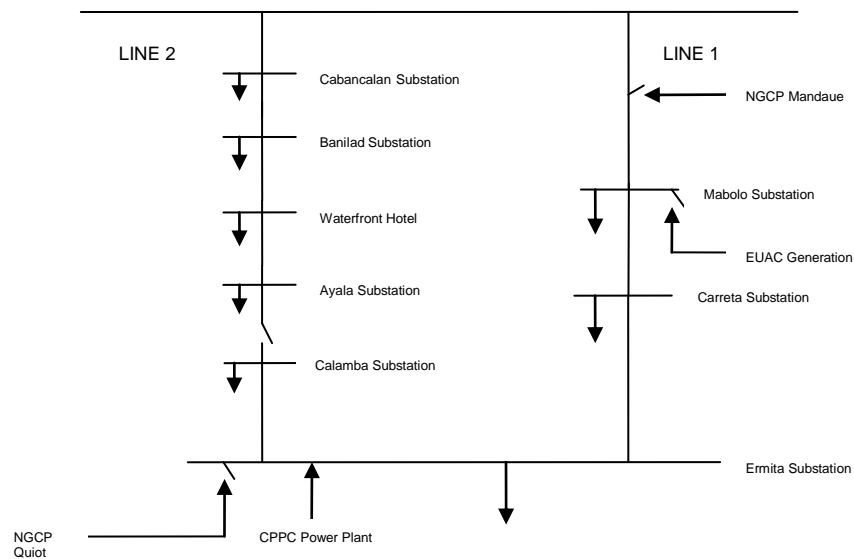


Table 4.6: Assumed Loads for Reliability Analysis (MVA)

Line 1		Line 2	
Substation	Load	Substation	Load
Ermita ¹	46.0	Calamba	29.5
Carreta ¹	55.7	Ayala	31.0
Mabolo	31.2	Waterfront	3.0
		Banilad	29.1
		Cabancalan	34.2
Total	133.8		126.8
Assumed diversity	10%		10%
ADMD Line Load	120.4		114.1

Note 1: These substations have two transformers.

The assumed capacity of each injection point is shown in Table 4.7.

²⁰ While the CPPC power station normally injects power into the network, injection from the EUAC plant is utilized only in emergencies.

Table 4.7: Injection Points

Source	Assumed Capacity (MVA)	Injection Point	Comment
NGCP Banilad	200	NGCP Banilad	Capacity limited by the available 138/69 kV transformer capacity.
NGCP Quiot	78	Ermita	VECO is proposing to disconnect the existing transformer at Quiot from the NGCP network and has assessed the available capacity based on contracted power input from CEDC. If the Quiot injection is limited to 45 MVA and 30 MVA is used at Pardo the available injection is only 15 MVA. However, we have recommended in Section 4.1 that the NGCP connection remain. In this event the CEDC input could be supplemented by input from NPC generation. Available injection capacity would be limited by the Quiot Pardo line (108 MVA) less the load at Pardo (30 MVA)
NGCP Mandaue	71	Tapping point on Line 1 between Banilad and Mabolo	Capacity limited by line capacity less load at VECO Mandaue substation. Switching arrangement at the tapping point is such that this is an alternative to injection into Line 1 from Banilad.
EAUC	30	Mabolo	Assumed reliable capacity based on one machine being out of service and some derating of the other three due to condition.
CPPC	50	Ermita	Assumed reliable capacity based on one machine being out of service and some derating of the other six due to condition.

Table 4.6 highlights an emerging problem in that by RY 2014 the loading on both lines will potentially exceed the line conductor rating in worst case contingency situations where there is a fault at one end of the line.

In the case of Line 1, if injection is lost from either end a line overload can be avoided by injection from the EAUC plant. This will effectively supply the Mabolo substation load and limit the remaining load to 90 MVA, which is within the line conductor rating. Sufficient injection capacity is available at either end to supply this load, although the situation would be marginal from the Ermita end if the injection capacity from Quiot is limited to the 45 MVA indicated by VECO.

If injection is lost from either end of Line 2, the load to be supplied from the other end will exceed the line rating and therefore load transfers using the 23 kV distribution network will be necessary. The connection of additional transformer capacity will not prevent this as the constraint is on the supply side. If the injection available from Quiot is limited it is possible that the power injection available from Ermita will be lower than the line rating and this will further exacerbate the situation.

The 69 kV switchyard at Ermita would seem to be VECO's short term strategy to address this contingency. It appears to be designed primarily to minimize the possibility of there being reduced injection capacity at Ermita as a result of a bus fault at the Ermita substation. It will also ensure that a bus fault will not cause an extended outage affecting both Ermita transformers.

The estimated project cost of PhP83.63 Million is substantial. It includes a provision of PhP25.85 Million for the purchase new 69 kV circuit breakers. VECO has not considered incorporating the existing Ermita 69 kV circuit breakers into the proposed breaker and a half switching arrangement – the single line diagram shows that these are to be left in their existing positions so that there would actually be two-and-a-half circuit breakers dedicated to each circuit. We think this is extreme and that VECO could have made significant savings had it proposed a configuration that incorporated or reused the existing circuit breakers.

Notwithstanding any inefficiency in the design of the project, we think the reliability impact of the project will be very limited as it protects only against substation bus faults. Such faults have a very low probability of occurring to the extent that they are often considered as non-credible contingencies by network designers. The proposed switching station will not alleviate the problem on Line 2 if it is caused by a line outage at the Banilad end of the line, a much more probable occurrence.

Hence, while we agree that the proposed project may result in a minor reliability improvement, we do not believe that the benefit is commensurate with the project cost and therefore recommend that it not proceed during the second regulatory period. While not shown in Figure 5.1, the Ermita substation's 69 kV bus is divided into two sections, separated by a bus coupler circuit breaker. We suggest that VECO ensure that the two Ermita transformers are connected to different bus sections and that the CPPC generating station and the Quiot-Pardo-Ermita lines are also connected to different bus sections. This is consistent with good industry practice and will provide some mitigation against bus faults.

We also think that a more significant reduction in reliability will result from a disconnection of Quiot from the NGCP network, because this would limit the injection capacity at Ermita.

Finally, we note that the project includes provision from the termination of a future 69 kV circuit between Quiot and Ermita. We think such a circuit is likely to be justified for construction during the third regulatory period, particularly if Quiot remains connected to the NGCP network but believe that VECO should review whether it should be terminated at Ermita. It appear to us that this line would be better terminated close to the mid-point of Line 2, possible at the Ayala or Camputhaw substations in order to split Line 2 into two sections.

The adjustment to the allowed capital expenditure though not proceeding with this project is shown in Table 4.8.

Table 4.8: Adjustments to Cost of Ermita Switching Station (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast			83.64			
Adjustment for deletion of Ermita Switching Station			(83.64)			

4.7 ERMITA TRANSFORMER 2

VECO has proposed the installation of a new 33 MVA 69/23 kV transformer at Ermita to replace the existing similar capacity 69/13.8 kV unit. The project has a forecast cost of PhP29.16 Million and was to have been commissioned by June 2009.

The transformer replacement is a result of VECO's upgrading of its legacy 13.8 kV distribution network to 23 kV, which we understand is due for completion in March 2010. We have not examined the merits of this upgrade in detail but note that it should result in a substantial reduction in the network technical losses within the affected area. It should also reduce inventory requirements and the flexibility of network operation through the use of a single distribution voltage across the whole network.

We therefore consider that the project should proceed and have not recommended any adjustment. This project has not been included in our high level assessment of the need for the proposed new transformer installations in Section 2.3.1.

4.8 JLUNA SUBSTATION

The new substation has a forecast installed cost of PhP98.62 Million and is scheduled for commissioning in September 2012. Consistent with the discussion in Section 2.3.1 we recommend that the project not proceed during the second regulatory period.

This adjustment to VECO's expenditure forecast is shown in Table 4.9:

Table 4.9: Adjustments to Cost of JLuna Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast					98.62	
Adjustment for deletion of JLuna substation					(98.62)	

4.9 MANDAUE TRANSFORMER 2

The new transformer has a forecast installed cost of PhP30.49 Million and is scheduled for commissioning in October 2010. Consistent with the discussion in Section 2.3.1 we recommend that the timing of the project be deferred until RY 2014.

This adjustment to VECO's expenditure forecast is shown in Table 4.10:

Table 4.10: Adjustments to Cost of Mandaue TR2 (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast			30.49			
Adjustment to timing of Mandaue TR2			(30.49)		30.49	

4.10 MINGLANILLA SUBSTATION

VECO is proposing to install a new substation in Minglanilla for a forecast cost of PhP94.21 Million. In its revenue application VECO indicated that commissioning was proposed for November 2009. We considered this substation in some detail early in the review since there did not appear to be an incoming supply available. The substation would need to be energized from the Naga-Pardo 69 kV line which, as discussed in Section 4.1.3 is not currently energized and was not included in the revenue application. We were only advised that it was under construction at a late stage of the review when we followed up on a number of inconsistencies in the information provided by VECO.

The major project information summary states that this substation is required to relieve the load on the Naga and Pardo substations. In 2008 the Naga substation had a peak demand of 25.5 MW and the Pardo substation peak demand was 21.0 MW. Ignoring any load diversity, the total maximum demand of the two substations was therefore 46.5 MW or 48.9 MVA assuming a 0.95 power factor. If an average load growth of 2.7% is assumed, the peak demand in 2014 will increase to 57.4 MVA. This is well within the combined 66 MVA rating of the two existing substation transformers. We further note that the forecast cost of this project is high because it is on a green field site.

We are therefore unable to recommend that the Minglanilla substation proceed during the second regulatory period. This adjustment is shown in Table 4.11.

Table 4.11: Adjustments to Cost of Minglanilla Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast		94.84				
Adjustment for deletion of Minglanilla substation		(94.84)				

A further concern that we have in respect of this project is that, while it was programmed for commissioning by November 2009 in the revenue application forecast, VECO subsequently advised that it has not yet decided on the exact location of the substation. The only conclusion we can reach is that VECO has allowed a project to be included in its CAPEX forecast when it knew (or should have known) that there was no chance of the project being completed by the forecast commissioning date.

4.11 NAGA-QUIOT 138 KV TRANSMISSION LINE

This transmission line is an extension of the 138 kV project discussed in Section 4.1 above. The project is intended to allow VECO's full contracted capacity of 105 MW to be absorbed into its distribution network. However, should VECO's proposed 138 kV line from the CEDC plant be terminated into NGCP's Naga substation, as recommended in Section 4.1, this line will not be required as its function will be performed by NGCP's existing Naga-Quiot 138 kV transmission line. We therefore recommend that this project not be approved.

The adjustment to reflect this recommendation is shown in Figure 4.12 below.

Table 4.12: Adjustment to Cost of Naga-Quiot 138 kV Transmission Line (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast				171.13		
Adjustment for deletion of Ermita Switching Station				(171.13)		

This recommendation is based on the information that has been made available to us by VECO for the purposes of this expenditure review and assumes that VECO and NGCP negotiate a project outcome along the lines described in Section 4.1. We would expect that these negotiations would be completed and their outcome reported to ERC in time for the final determination. We would also expect that at that time VECO would have completed a power purchase contract with CEDC and submitted it to the ERC for approval. We acknowledge that it may be necessary for us to revise our recommendation at that point in order to take account the new information that we expect will be available at the time the ERC prepares its final determination.

4.12 NAGA-SIBONGA SUBTRANSMISSION LINE ACQUISITION

VECO has included a provision of PhP20.65 Million in its CAPEX forecast for the purchase of the section of the Naga-Sibonga 69 kV line within its franchise area from NGCP. It is proposed that this transaction will occur in June 2012. The purchase cost provision is based on an estimate of 30% of the assessed sound value of the asset, based on the proportion of the asset within VECO's franchise area.

This purchase was not referenced in VECO's revenue application so it was not discussed at the clarificatory meeting. It came to light only after VECO submitted a project sheet for the purchase following the clarificatory meeting. Hence VECO has supplied insufficient information to allow us to assess whether the purchase is likely to be approved by the ERC in the form proposed by VECO.

We therefore approached ERC for further information. ERC confirmed to us that it received an application from TransCo to sell the assets to a VECO-CEBECO I Consortium on October 30 2007. This application is docketed as Case No 2007-492-MC and there have been two public hearings on the case. It is now pending a final decision by the Commission.

We are advised that on February 18 2009, TransCo submitted an amendment to the contract to sell the assets with a renegotiated contract price of PhP50.45 Million, which we note is almost 27% lower than the PhP68.84 Million²¹ advised by VECO following the clarificatory meeting. It also advised that VECO holds only 29% of the shares in the consortium. We also understand that, while no final decision has been made, ERC staff considers that there is no impediment to the sale of the asset at the renegotiated contract price. VECO's share of this contract price is PhP14.63 Million.

We therefore recommend that provision for the purchase of the asset be included in the CAPEX forecast, based on the renegotiated purchase price and VECO's 29% shareholding. This implies a reduction of PhP6.02 Million to the provision included in the revenue application. This adjustment is shown in Table 4.13 below.

Table 4.13: Adjustments to Purchase Price of Naga-Sibonga Subtransmission Line

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast				20.65		
Purchase Price Adjustment				(6.03)		

Finally, we note that VECO has not included any provision for this purchase in the line item *transferred subtransmission assets* in the CAPEX template submitted with its revenue application. We understand that the provision has been incorrectly recorded in the *poles, towers and fixtures* and *overhead conductors and devices* line items.

4.13 NORTH RECLAMATION AREA (NRA) SUBSTATION

VECO is proposing to install a new substation in the North Reclamation Area for a forecast cost of PhP77.06 Million. In its revenue application VECO indicated that commissioning was proposed for June 2009. However our analysis in Section 2.3.3 indicates that this substation is not required until RY 2011. We therefore propose that the timing of the project be adjusted in accordance with Table 4.14.

Table 4.14: Adjustments to Timing of NRA Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast	77.06					
Impact of Timing Adjustment	(77.06)		77.06			

As noted in Section 3 VECO has applied for approval of the capital expenditure on this project. This expenditure was approved on 24 November 2008²². We acknowledge that our recommendation is in conflict with the ERC decision and that the ERC may need to let its earlier decision stand. However our terms of reference require us to review all budgeted or forecast CAPEX after 31 December 2008, and we believe the ERC wants us to review all expenditure on its merits without regard to its previous decisions.

ERC is not obligated to accept our recommendations and it may well be appropriate for it to allow the expenditure to be incurred earlier in accordance with its 2008 decision. In this event we suggest that it require VECO to explain the difference between the forecast cost of PhP63.72 Million in its approved case and the provision for the same project in its

²¹ PhP68.84 million was the original purchase price.

²² ERC Case No 2008-085 MC.

ERC revenue application. It should also ask VECO to confirm that the commissioning date of June 2009 was actually achieved.

4.14 QUIOT 138 KV SUBSTATION

VECO's capital expenditure forecast includes a provision of PhP125.65 Million for the purchase of the Quiot substation from NGCP. It is assumed that the transaction will be finalized in June 2012.

The Quiot substation is supplied by one circuit of the 138 kV Banilad-Naga line, which forms part of NGCP's 138 kV backbone link between Leyte and Negros. It currently consists of 138 kV switchgear, a 100 MVA 138/69 kV transformer and three 69 kV circuit breakers. There is provision for substation to be expanded into a much larger facility. We understand that construction was completed in late 2007 or early 2008.

On 8 February 2008, VECO submitted a petition to the ERC, docketed as Case No 2008-033 MC arguing that the Quiot substation should be reclassified as a subtransmission asset. While the petition provided a number of grounds to support this argument, essentially VECO argued that the substation was constructed only to inject electricity into its distribution network and that it was the only distribution utility that the substation supplied.

NGCP has responded to the petition by arguing that:

- the substation forms a part of the main electricity transmission highway between Leyte and Negros;
- the transformer provides a vital transmission function in that it provides power to NGCP's telecommunications and protection systems; and
- NGCP has future plans for upgrading the substation as the need arises.

The ERC has still to issue its decision on this petition. We comment that:

- the ERC promulgated its guidelines for the classification of subtransmission assets in 2003;
- the Quiot substation has only recently been completed for the specific purpose of providing a supply to VECO. It is reasonable to assume that in the early stages of the development of the project VECO was happy for the asset to be owned by TransCo, notwithstanding the existence of the ERC guidelines. We therefore cannot accept the VECO statement in its petition that *[it] had no way of knowing or verifying as to the possible classification of the substation (i.e. whether transmission or subtransmission) because it was still under construction at that time.*
- in its petition VECO did not explicitly state what assets it sought to acquire. We think it should have recognized that the 138 kV infrastructure was an integral component of what is arguably the most important transmission line on the Visayas grid and that therefore NGCP was unlikely to agree to relinquish control of the asset. It should also have recognized that ERC was unlikely to agree to its purchase of these assets for the same reason.
- at the clarificatory meeting VECO indicated that it was planning to disconnect the 138/69 kV transformer from the 138 kV infrastructure (which we emphasize has only recently been constructed) and to supply the transformer from its proposed 138 kV Naga-Quiot line (see Section 4.1) and we suspect this could be the real reason for its petition. A consequence of this would be that the 138 kV infrastructure at Quiot would need to be optimized out of the NGCP asset base as no longer being required. This outcome would be extremely harsh on NGCP,

given that the construction of the assets has only recently been completed and was undertaken in good faith, presumably with the concurrence VECO. We also note that our analysis of the Ermita 69 kV switchyard project (see Section 4.6) has indicated that disconnection of the transformer from the NGCP grid could have a material and adverse impact of the reliability of the VECO distribution network. Hence we consider that any such disconnection is likely to be only temporary.

- while the VECO petition did not explicitly specify the assets involved, we are satisfied that the requested PhP125.65 Million is sufficient only to cover the purchase of the transformer and the associated 69 kV infrastructure. This implies that VECO no longer wishes to purchase the 138 kV transmission assets.

We understand that VECO's proposed purchase price is based on estimated "as new" cost of the assets. We are unable to verify the reasonableness of this estimate (other than to satisfy ourselves that it is insufficient to provide for the 138 kV infrastructure) as we have insufficient detail regarding the specific assets involved. We understand that ERC is inclined to approve the reclassification of the transformer and 69 kV switchgear as subtransmission assets and to allow VECO to purchase the assets. We concur with this although, if ERC accepts the conclusions of our analysis and the recommendations in this report, we suggest that approval is only granted on condition that VECO does not disconnect the transformer from the grid without the ERC's explicit consent. We also suggest that the purchase price be based on the outcome of the current SKM valuation of NGCP assets and that the ERC's decision on this case provide for an adjustment at the time of the revenue reset for the third regulatory period to cover the impact of any difference between the actual purchase price and the price assumed in this report.

Notwithstanding this recommendation, we conclude that the VECO petition is evidence that VECO and NGCP may not be collaborating in a constructive manner to ensure that planning decisions being made that are in the long term interest of consumers. This conclusion is further supported by the result of our analysis of the 138 kV project (see Section 4.1) and the Ermita 69 kV switchyard (see Section 4.6). Good electricity industry practice requires at transmission and distribution utilities engage in "joint planning" at connection points to ensure least cost development outcomes that are in the long term interests of grid users rather than the specific business interests of the individual businesses and the ERC is entitled to expect no less of both VECO and NGCP. This philosophy of seeking outcomes consistent with the common good requires a good relationship and close and ongoing communication between the parties.

4.15 SOUTH ROAD PROJECT (SRP) SUBSTATION

The new transformer has a forecast installed cost of PhP76.36 Million and is scheduled for commissioning in July 2013. Consistent with the discussion in Section 2.3.1 we recommend that the project not proceed during the second regulatory period.

This adjustment to VECO's expenditure forecast is shown in Table 4.15:

Table 4.15: Adjustments to Cost of SRP Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO Forecast						76.36
Adjustment for deletion of SRP substation (Table 4.15)						(76.36)

4.16 CUSTOMER CARE & BILLING SYSTEM

In its revenue application, VECO has included forecast CAPEX of PhP45.40 Million to cover its share of a new Oracle customer care and billing system that Aboitiz Power Company (APC) is planning to install for use by all its distribution utilities. It anticipates

the system will be commissioned in RY 2010. Following the clarificatory meeting it revised the cost upwards to PhP71.23 Million to be consistent with the cost allocation chart included in the DLPC revenue application.

The DLPC revenue application also included a complete description of the system to be installed and a copy of the proposal from Oracle Consulting Services to provide the system. The package offered is an integrated software package designed to handle every aspect of utility customer information including service connection, meter reads, rating billing, and more and is intended to be configurable to different regulatory requirements and rating systems. Hence it should be readily adaptable to changes in the industry or regulatory environment.

The system proposed is a “state of the art” solution that would be purchased by APC and would serve as a centralized billing and customer information system for use by all APC utilities. We think this approach is efficient – on its own the cost would be excessive for any single utility. However the approach proposed will standardize the approach to customer management across all APC utilities and will allow all access to world class utility software. We believe that APC has the expertise to successfully implement and utilize such a system.

The estimated total implementation cost of the system is PhP142.31 Million, based on an implementation cost of PhP74.43 Million, as set out in the Oracle proposal. The additional costs include license and annual support costs²³. There is also a total of PhP26.25 Million of costs that are internal to VECO, including hardware costs, training and the provision of internal implementation support. We consider the total cost to be reasonable and the basis for allocating this cost between the various APC utilities to be reasonable.

We recommend that the cost of the project be included in the approved CAPEX forecast. We note however that VECO has stated that the project is to be implemented by June 2009 and has provided for this expenditure in the forecast period January-June 2009. This contrasts with the DLPC revenue application, which assumes a June 2010 implementation date.

The proposal included in the DLPC revenue application was dated November 2008 and provided for an 11 month implementation period, with system roll-out not occurring until month 10. This precludes a June 2009 implementation. We have adjusted the forecast to be consistent with a June 2010 implementation, as shown in Table 4.16

Table 4.16: Adjustments to Timing of customer care & billing system (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	45.40					
Impact of Timing Adjustment	(45.40)	71.23				

4.17 SUMMARY OF MAJOR PROJECT EXPENDITURE

Table 4.17 below provides a breakdown of VECO's forecast major project expenditure into individual projects. The template total for Jan-Jun 2009 has been derived from the figures supplied in the revenue application to eliminate the overlap between CY 2009 and RY 2010.

Table 4.17: Breakdown of Forecast Major Project Expenditure (PhP Million, real)

²³ APC has assumed that the one-off license cost and the first year's annual support costs will be capitalized. Subsequent year's annual support costs will be treated as OPEX.

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Revenue Application Template	247.96	94.84	984.11	422.95	98.62	106.27
Revised Major Project Sheets						
138KV project			869.98			
Banilad TR2						29.91
Cotcot line purchase				8.00		
Calamba TR2				97.52		
Camputhaw substation	96.34					
69KV Ermita switchyard			83.64			
Ermita TR2	29.16					
JLuna substation					98.62	
Mandaue TR2			30.49			
Minglanilla substation		94.84				
Naga-Quiot 138 kV line				171.13		
Naga Sibonga line purchase				20.65		
NRA substation	77.06					
Quiot substation purchase				125.65		
SRP substation						76.36
Customer management system	45.40					
Total Major Projects	247.96	94.84	984.11	422.95	98.62	106.27

The recommended adjustments for individual projects are summarized in Table 4.18 below.

Table 4.18: Summary of Individual Adjustments (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Deletion of 138 kV Naga Substation (Table 4.2)			(406.05)			
Deletion of Banilad TR2 (Table 4.3)						(29.91)
Adjustment to Banilad-Cotcot line purchase cost (Table 4.4)				(0.89)		
Deletion of Calamba TR2 (Table 4.5)				(97.52)		
Deletion of Ermita 69 kV switching station (Table 4.8)			(83.64)			
Deletion of JLuna substation (Table 4.9)					(98.62)	
Adjustment to timing of Mandaue TR2 (Table 4.10)			(30.49)		30.49	
Deletion of Minglanilla substation (Table 4.11)		(94.84)				
Deletion of Naga-Quiot Line (Table 4.12)				(171.13)		
Adjustment to Naga-Sibonga line purchase cost (Table 4.13)				(6.03)		
Adjustment to timing of NRA substation (Table 4.14)	(77.06)		77.06			
Deletion of SRP substation (Table 4.15)						(76.36)
Adjustment to timing of customer care & billing system	(45.40)	71.23				
Total	(122.46)	(23.61)	(443.12)	(275.57)	(68.13)	(106.27)

Our recommended major project CAPEX for the second regulatory period is shown in Table 4.19 and a comparison between the VECO forecast and our recommendation is shown in Figure 4.1.

Table 4.19: Summary of Recommended Major CAPEX Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Revenue application template	247.96	94.84	984.11	422.95	98.62	106.27
Recommended adjustments	(122.46)	(23.61)	(443.12)	(275.57)	(68.13)	(106.27)
Recommended major project CAPEX	125.50	71.23	540.99	147.38	30.49	-

Figure 4.1: Comparison of VECO Forecast and Recommended Major Project CAPEX

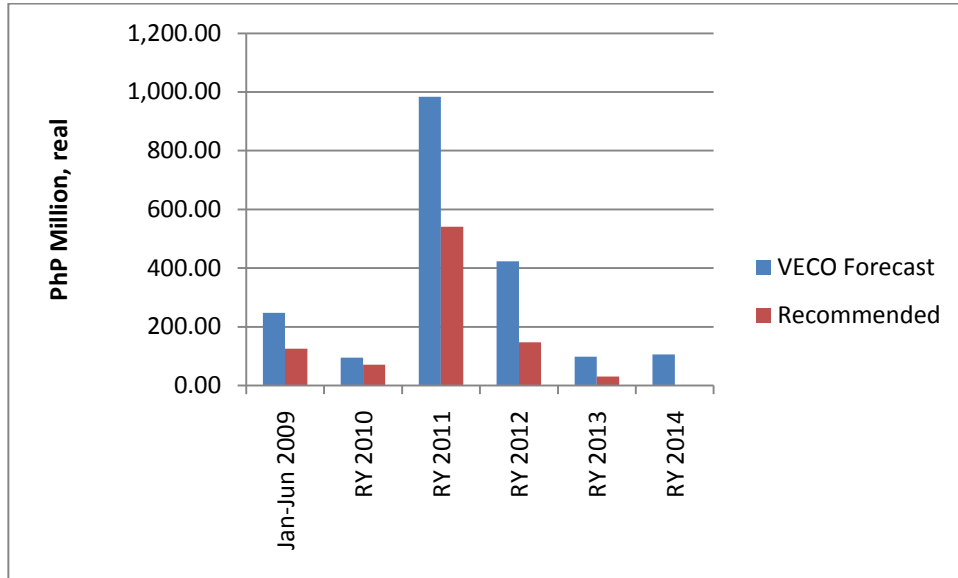


Table 4.20 breaks down the major project expenditure into the major OPEX expenditure drivers. All network projects involve the construction of new assets and so are classified as network growth. The projects involving the purchase of assets from NGCP have been separately categorized and the customer care and billing system is categorized as non-network replacement given that it replaces existing systems that have a similar (albeit less sophisticated) functionality.

Table 4.20: Breakdown of Recommended CAPEX by OPEX Driver (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Network growth	125.50		540.99		30.49	
Purchased subtransmission Assets				147.38		
Non-network replacement		71.23				
Total	125.50	71.23	540.99	147.38	30.49	-

5. RESIDUAL CAPITAL EXPENDITURE

5.1 INTRODUCTION

VECO has provided very little information on either its historical or forecast residual CAPEX. For the historical years CY 2004-08 it was able to provide its total CAPEX but did not separate out major project expenditure. Hence the only full historical or budget year for which we have residual expenditure data broken down by the standard ERC expenditure projects is CY 2009.

VECO's expenditure forecast also identified a number of specific projects that were included in the residual CAPEX forecast. These are shown in Table 5.1 but represent only 4.5% of the total forecast residual CAPEX in all categories over the period January 2009 – June 2014.

Table 5.1: Specifically Identified Residual CAPEX Expenditure

Item	Cost ¹	Timing	ERC Category	Comment
2 Mitsubishi L300 vans	1.12	RY 2014	Non-network renewal	
12 Honda XR200 motorbikes	1.39	RY 2011	Non-network renewal	
Electric forklift	1.16	RY 2010	Non-network growth	Should be categorized as renewal
Mango receiving office	1.90	Jan-Jun 2009	Non-network growth	
Hydraulic lifter	1.50	RY 2010	Non-network growth	
High speed laser printer	2.00	Jan-Jun 2009	Non-network refurbishment	Should be categorized as renewal
Database shared storage system	3.50	Jan-Jun 2009	Non-network growth	Should be categorized as renewal
Novell network licenses	3.60	Jan-Jun 2009 RY 2010 RY 2011	Non-network growth	New licenses
Oracle works and asset management software	29.00	RY 2013	Non-network growth	DLPC has provided for a similar Oracle system.
Covered walk	1.10	Jan-Jun 2009	Non-network refurbishment	
Linemen's quarter	8.00	RY 2010	Non-network renewal	
Light bucket truck	2.00	RY 2010 RY 2014	Non network growth	
Aerial platform bucket	7.45	RY 2010	Non network growth	
4 drum puller	7.61	Jan-Jun 2009	Non network growth	
Wood chipper	2.19	Jan-Jun 2009	Non network growth	
105 ft articulating folding boom	22.20	Jan-Jun 2009	Non network growth	
Total	95.72			

Note 1: PhP Million real

5.2 GROWTH RELATED RESIDUAL CAPITAL EXPENDITURE

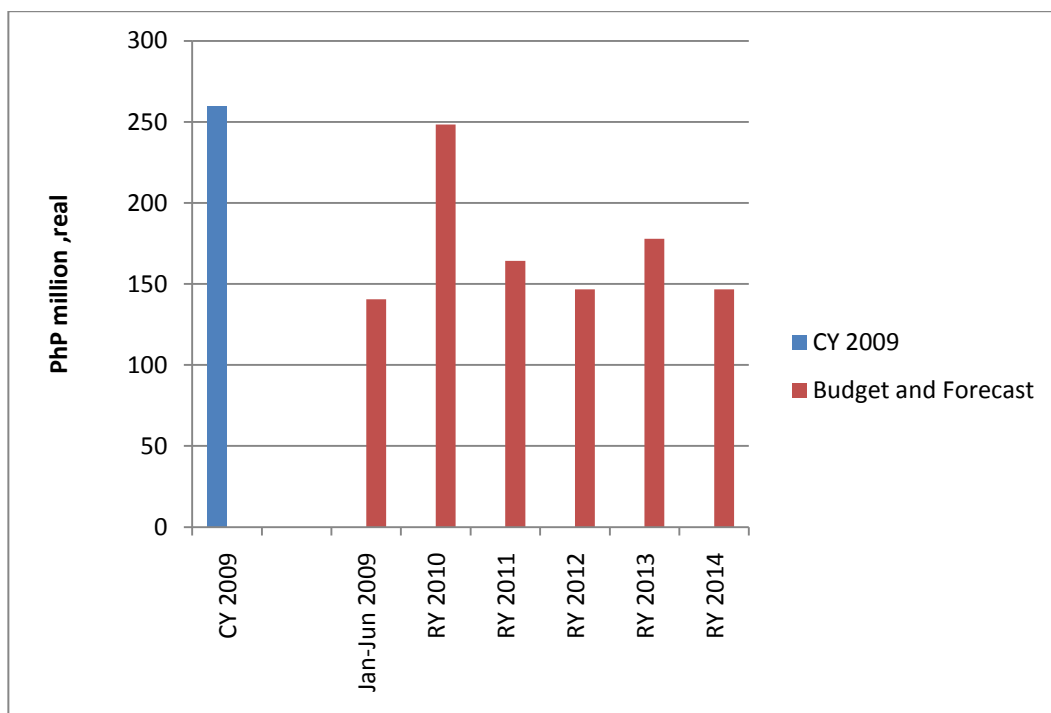
VECO’s growth related residual capital expenditure, taken from the CAPEX template submitted with its revenue application, is shown in Table 5.2 below.

Table 5.2: Growth Related Residual CAPEX (PhP Million, real)

Budget CY 2009	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
259.51	140.52	248.28	164.24	146.73	177.79	146.57

This expenditure is shown graphically in Figure 5.1.

Figure 5.1: Budget and Forecast Residual Growth CAPEX (PhP Million, real)



It can be seen from Figure 5.1 that VECO’s budgeted residual growth CAPEX in CY 2009 is very high compared to the majority of the forecast years, which would indicate that CY 2009 residual growth CAPEX may not be an appropriate benchmark on which to assess the residual growth CAPEX in the forecast years. This CAPEX appears to be driving high levels of expenditure forecast over the period January 2009–June 2010 and the reason for this is considered below.

5.2.1 January 2009 – June 2010

The high level of residual growth CAPEX over this period can be attributed largely to the line items shown in Table 5.3. We have divided the affected line items into three groups and have analyzed each group individually. The spread of expenditure for each group between the Jan-Jun 2009 period and RY 2010 is shown in Table 5.4

Network Assets - Distribution

The increased level of expenditure on these assets, including the categories of station assets affected, is consistent with the upgrading of the 13.8 kV network in the central business district to 23 kV. VECO stated at the evidentiary hearing that this work was currently being undertaken and was scheduled for completion in March 2010. The

spread of expenditure shown in Table 5.4 is consistent with this. As discussed in Section 4.7, we see significant benefits in this upgrade and do not recommend an adjustment to these line items.

Table 5.3: Review of Selected Residual Growth CAPEX Line Items (PhP Million, real)

Line Item	Budget CY 2009	Average Annual Forecast (RY 2011-14)	2009 Increase
Network Assets - Distribution			
Station protective equipment	5.78	3.04	90%
Station metering & control equipment	14.66	5.11	187%
Station communications equipment	4.33	1.25	247%
Other station equipment	1.95	0.34	470%
Poles, towers and fixtures - distribution	57.92	20.78	179%
Overhead conductors and devices - distribution	17.64	4.96	256%
Subtotal	102.28	35.48	188%
Transportation Equipment			
Distribution	26.18	1.39	1783%
Connection Services	6.28	0.02	26666%
Retail Services	4.60	0.98	370%
Subtotal	37.06	2.39	1450%
Laboratory Equipment	2.17	-	-

Table 5.4: Spread of Selected Residual Growth Expenditure Groups (PhP Million, real)

	Jan-Jun 2009	RY 2010
Network assets - distribution	34.59	121.75
Transportation equipment	36.40	1.99
Laboratory equipment	2.17	2.91

Transportation Equipment

It can be seen from Table 5.4 that VECO is planning to spend a total of PhP38.39 Million on transportation equipment over the 18 month period Jan 2009-Jun 2010. Of this PhP36.40 Million (95%) is planned to be spent over the period Jan-Jun 2009. This will include the aerial platform bucket, the four drum puller and the 105 ft articulating folding boom, which together cost a total of PhP37.26 Million²⁴. We have renewed the need for these three equipment items based on the reduced level of major project CAPEX recommended in Section 4.17.

The most expensive plant item is the PhP22.20 Million, 105 ft articulated folding boom that, in its project sheet, VECO has stated it is proposing to purchase in preparation for the construction and maintenance of its 138 kV lines. VECO's does not currently own or operate any 138 kV line but its CAPEX forecast included for the construction of a total of 50 km of new line. While we have recommended that 37 km proceed, we expect this

²⁴ The fact that the total cost of these three items exceeds the total forecast expenditure on transportation equipment for the period Jan-June 2009 indicates some inconsistency between the template and the residual CAPEX project sheets. However this inconsistency is not material to the results of the analysis and has been ignored.

eventually to be operated as part of the NGCP network. We consider that the purchase of such an expensive piece of plant to assist with the construction and maintenance of a relatively short length of 138 kV line to be an extravagance and we therefore think it unreasonable for VECO to expect its customers to fund it. Should there be a need for VECO to use such equipment then it should hire it, possibly from NGCP. If the equipment is not available from NGCP or other similar contractor then we question VECO's requirement on that basis alone – if NGCP can operate without such equipment then it is reasonable to expect the same of VECO. We therefore recommend that funding for the purchase of the articulated folding boom not be approved.

We have similar concerns regarding the purchase of the PhP7.61 Million 4 drum puller. At the evidentiary hearing VECO stated that it was unable to find a similar piece of equipment anywhere in the Visayas and neither NGCP nor its contractors had one. Again, we think this in itself indicates that the purchase of this plant by VECO is an extravagance. We think VECO should be leaving line contractors to make their own decisions as to what plant they need to efficiently construct high voltage overhead lines and should not be asking their customers to buy equipment for contractors to use. We recommend that funding for the drum puller not be approved.

As a general rule we think VECO should be hiring, rather than buying, very expensive plant for which it is likely to be only to put to intermittent use. Should it decide to buy such plant, it should be looking to hire it out to other users in order to maximize the use of the assets. In this event we don't think the VECO should expect its customers to fund the capital cost, although it is reasonable for the regulated distribution business to be charged for the use of this equipment at market rates.

We reviewed the need for the PhP7.45 Million aerial platform bucket in the light of this principle. While we have some reservations, we acknowledge its potential usefulness for 69 kV line maintenance and recommend this expenditure be approved.

Laboratory Equipment

VECO has included in its revenue forecast a provision of PhP5.08 Million for laboratory equipment over the period Jan 2009-June 2010. It has provided no information as to what the equipment is, how frequently it will be used and whether it is possible to hire the equipment as required from NGCP or other parties. No expenditure on laboratory equipment is proposed for the remainder of the forecast period. We consider the cost of these one-off purchases to be material and, given that no information is provided on what the funds would be spent on or why they are required, we are unable to recommend the expenditure be approved.

5.2.2 RY 2013

In this section we consider expenditure forecast for RY 2013, which is another year in which the forecast expenditure is particularly high.

Works and Asset Management Software

The other major expenditure item in Table 5.1 is the PhP29.00 Million expenditure in RY 2013 on works and asset management software. While this is classified on the project information summary as non-network growth the expenditure is not shown on the residual growth CAPEX template. It is discussed further in Section 5.3 below.

Network Assets

The major reason for the high level of residual growth expenditure in RY 2013 relates to the inclusion of expenditure on the line items shown in Table 5.5.

Table 5.5: Line Items with high Residual Growth Expenditure RY 2013 (PhP Million, real)

Line Item	Forecast Expenditure RY 2013
Structures and improvements	1.02
Protective equipment	12.14
Other station equipment	1.37
Underground cables and devices - distribution	0.26
Meters, instruments and metering transformers - distribution	5.23
Miscellaneous equipment	3.43
Total	23.45

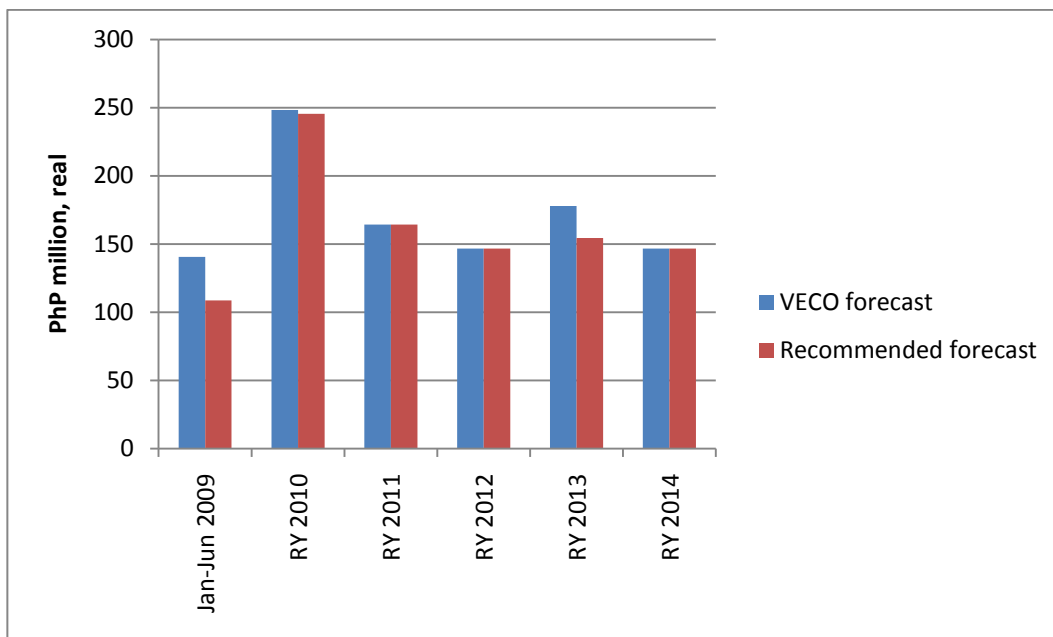
As the total expenditure on these line items for the other three years of the second regulatory period is only PhP0.08 Million it is reasonable to assume that these expenditures relate to a single one-off project. VECO has not provided any explanation for this expenditure but we think it may relate to the protection and metering of the proposed 138 kV Naga-Quiot line, scheduled for commissioning in June 2012. We have recommended that expenditure on this proposed line not be approved. Even if the above expenditure is not associated with the 138 kV line, as part of this review we have analyzed the operation of VECO's subtransmission and distribution system in some detail and see no requirement for additional substation growth related expenditure of this magnitude. We therefore recommend that the forecast expenditure shown in Table 5.5 not be approved.

The impact of the adjustments recommended above is shown in Table 5.6 and graphically in Figure 5.2 below.

Table 5.6: Adjustments to Residual Growth CAPEX Forecast (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	140.52	248.28	164.24	146.73	177.79	146.57
Deletion of articulated folding boom	(22.20)					
Deletion of puller	(7.61)					
Deletion of laboratory equipment	(2.17)	(2.91)				
Deletion of distribution network expenditure					(23.45)	
Recommended forecast	108.54	245.37	164.24	146.73	154.34	146.57

Figure 5.2: Comparison of VECO and Recommended Residual Growth CAPEX Forecast



5.3 RENEWAL RELATED RESIDUAL CAPITAL EXPENDITURE

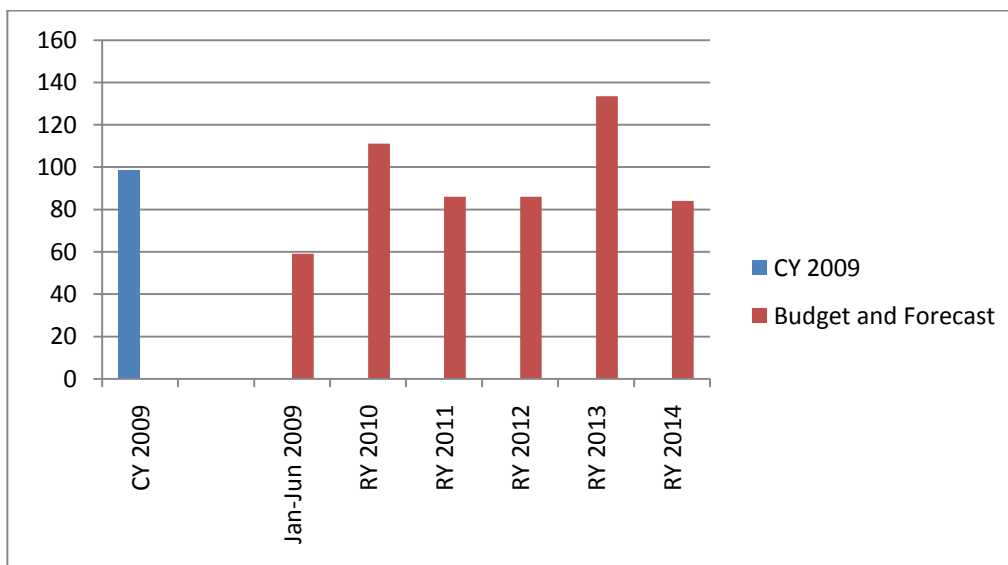
VECO’s renewal related residual capital expenditure, taken from the CAPEX template submitted with its revenue application, is shown in Table 5.7 below.

Table 5.7: Renewal Related Residual CAPEX (PhP Million, real)

Budget CY 2009	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
98.47	59.06	111.17	86.02	85.99	133.52	84.08

This expenditure is shown graphically in Figure 5.3.

Figure 5.3: Budget and Forecast Residual Renewal CAPEX (PhP Million, real)



It can be seen from Figure 5.3 that, when compared to the benchmark CY 2009, VECO's forecast expenditure in RY 2010 and RY 2013 is high. Forecast expenditure in other years is more reasonable.

5.3.1 RY 2010

A review of the CAPEX template indicates that the abnormally high expenditure in RY 2010 is a result of the following line items:

Transportation Equipment – Distribution

Forecast expenditure on this line item is PhP8.62 Million for the eighteen month period Jan 2009-Jun 2010 compared to an average annual expenditure of PhP2.13 Million over the four years of the second regulatory period. No explanation has been provided for this abnormally high level of expenditure, which is not adequately covered in the projects itemized in Table 5.1. We recommend that expenditure on this line item be reduced to PhP1.07 Million in the period Jan-June 2009 and PhP2.13 Million in RY 2010 to reflect the average level of expenditure over the remaining years of the forecast period.

Transportation Equipment – Connection Services

Forecast expenditure on this line item is PhP1.65 Million in RY 2010 compared to an average annual expenditure of PhP0.23 Million over the four years of the second regulatory period. No explanation has been provided for this abnormally high level of expenditure, which is not adequately covered in the projects itemized in Table 5.1. We recommend that expenditure on this line item be reduced to PhP0.23 Million reflect the average level of expenditure over the remaining years of the forecast period.

Information Systems - Distribution

Forecast expenditure on this line item is PhP21.19 Million for RY 2013. The only other expenditure shown in the template against this line item is PhP0.41 Million in RY 2010. No explanation has been provided for this substantial expenditure, which is not adequately covered in the projects itemized in Table 5.1.

However this expenditure is consistent with the expenditure on the SCADA EMS software, for which a major project information summary was provided in the DLPC revenue application. This summary indicated that the Aboitiz Power Company (APC) was planning to standardize on the SCADA software used by all APC distribution utilities. We reviewed the merits of this approach as part of the DLPC expenditure review and concluded that it was reasonable. We therefore recommend that the expenditure be allowed.

Information Systems – Non Network

Forecast expenditure on this line item is PhP31.14 Million for RY 2013. We assume it is the expenditure on the works and asset management system shown in Table 5.1, even though this expenditure is classified as non-network growth in its project information sheet.

We accept the usefulness of such a system when properly implemented and acknowledge that similar systems are used by leading utilities internationally. However in this case we think it appropriate that the software be purchased by APC and shared by all APC utilities. As DLPC has included provision for a similar system in its revenue application we assume that is what is proposed. Notwithstanding this, no information has been provided on the forecast total cost of the system and how this cost would be shared by the different utilities.

Given this, and having regard to the overall magnitude of the VECO CAPEX forecast, we recommend that this expenditure be deferred until the third regulatory period. During this

regulatory period APC should carefully assess the requirements of the different utilities and to present a properly developed and costed proposal in the revenue application for the third regulatory period.

We recommended that the expenditure on this line item for RY 2013 be reduced to PhP1.30 Million to reflect the average expenditure on this line item over the remaining three years of the second regulatory period.

Meters, Instrument and Metering Transformers (Consumer Metering)

Forecast expenditure on this line item is PhP21.48 Million for the six month period Jan-Jun 2009, which we consider high over six months when compared to the average annual expenditure of PhP27.76 Million over the remainder of the forecast period. No explanation has been provided for the high level of expenditure over the six month period, and we would expect expenditure on this line item not to vary significantly in real terms over time. We therefore recommend that expenditure on this line item be reduced to PhP13.88 Million in the period Jan-June 2009 to reflect the average level of expenditure over the remainder of the forecast period.

The impact of the adjustments recommended above is shown in Table 5.8 and graphically in Figure 5.4 below.

Table 5.8: Adjustments to Residual Growth CAPEX Forecast (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	59.06	111.17	86.02	85.99	133.52	84.08
Reduction in expenditure on <i>transportation equipment distribution</i>	(0.70)	(4.73)				
Reduction in expenditure on <i>transportation equipment connection services</i>		(1.42)				
Reduction in expenditure on <i>information systems – non-network</i>					(29.84)	
Reduction in expenditure on <i>meters, instruments and metering transformers</i>	(7.60)					
Recommended forecast	50.76	105.02	86.02	85.99	103.68	84.08

Figure 5.4: Comparison of VECO and Recommended Residual Renewal CAPEX Forecast



5.4 REFURBISHMENT RELATED RESIDUAL CAPITAL EXPENDITURE

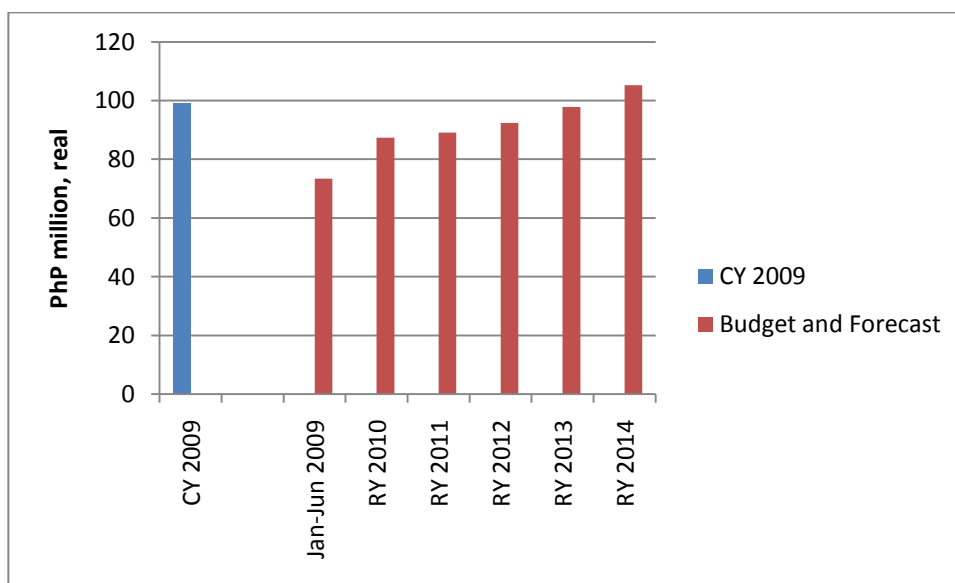
VECO’s refurbishment related residual capital expenditure, taken from the CAPEX template submitted with its revenue application, is shown in Table 5.9 below.

Table 5.9: Renewal Related Residual CAPEX (PhP Million, real)

Budget CY 2009	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
99.09	73.37	87.34	89.08	92.35	97.85	105.23

This expenditure is shown graphically in Figure 5.3.

Figure 5.5: Budget and Forecast Residual Refurbishment Capital Expenditure (PhP Million, real)



We are surprised that overall expenditure on refurbishment is higher than renewal, since we would normally expect it to be significantly lower. Unfortunately we have not explored

this in detail with VECO but note that it could be related to the way it defines expenditure for cost allocation purposes²⁵. We also note the relatively high expenditure budgeted for Jan-June 2009 (which accounts for the high level of benchmark expenditure in CY 2009) and the progressively increasing level of expenditure over the forecast period. We note that VECO has provided no information in its revenue application to justify this expenditure.

We have reviewed this expenditure forecast line by line and recommend the following adjustments. In undertaking this review we have assumed that unit material and labor costs and refurbishment volumes will generally remain constant. We think this is a reasonable assumption for this regulatory period, particularly as some residual refurbishment expenditure is discretionary.

Transformers

VECO has budgeted PhP2.45 Million in Jan-Jun 2009 and PhP3.05 Million in RY 2010. Forecast annual expenditure then rises progressively to reach PhP3.57 Million in RY 2014. We recommend that all expenditures be adjusted to reflect a base annual expenditure of PhP3.05 Million.

This adjustment is shown in Table 5.10

Table 5.10: Adjustment to Forecast Residual Transformer Refurbishment Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	2.45	3.05	3.36	3.47	3.57	3.57
Recommended Expenditure	1.53	3.05	3.05	3.05	3.05	3.05
Adjustment	(0.92)	-	(0.31)	(0.42)	(0.52)	(0.52)

Overhead Conductors and Devices – Distribution

VECO has budgeted PhP3.46 Million in Jan-Jun 2009 and PhP4.99 Million in RY 2010. Forecast annual expenditure then rises progressively to reach PhP4.33 Million in RY 2014. We recommend that all expenditures be adjusted to reflect a base annual expenditure of PhP4.99 Million.

This adjustment is shown in Table 5.11

Table 5.11: Adjustment to Forecast Residual Conductor and Devices Refurbishment Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	3.46	4.99	5.04	5.13	5.23	5.33
Recommended Expenditure	2.50	4.99	4.99	4.99	4.99	4.99
Adjustment	(0.96)	-	(0.05)	(0.14)	(0.24)	(0.34)

Streetlights and Signal Systems - Distribution

VECO has budgeted PhP5.09 Million in RY 2010. Forecast annual expenditure then rises progressively to reach PhP19.71 Million in RY 2014. We recommend that all expenditures be adjusted to reflect a base annual expenditure of PhP5.09 Million.

²⁵ Section 5.1.2 of the Group C Position Paper refers to Appendix N as providing a description of the different CAPEX cost categories. However, this appendix appears to have been omitted from the published version of the paper.

This adjustment is shown in Table 5.12

Table 5.12: Adjustment to Forecast Residual Streetlight Refurbishment Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	1.83	5.09	7.14	10.24	14.49	19.71
Recommended Expenditure	1.83	5.09	5.09	5.09	5.09	5.09
Adjustment	-	-	(2.05)	(5.15)	(9.40)	(14.62)

Structures and Improvements – Non-Network

VECO has budgeted PhP16.08 Million in Jan-Jun 2009 and PhP1.50 Million in RY 2010. No expenditure is forecast in the remaining years of the forecast period. We suspect this relates to building improvements but no information has been provided, except for PhP1.10 Million expenditure on a covered walk, for which a project sheet has been provided (see Table 5.1). We recommend that this expenditure, except for the budgeted expenditure on the covered walk, not be approved.

This adjustment is shown in Table 5.13

Table 5.13: Adjustment to Forecast Residual Streetlight Refurbishment Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	16.08	1.50				
Recommended Expenditure	1.10					
Adjustment	(14.98)	(1.50)				

Meters, Instruments and Metering Transformers – Retail Services

VECO has budgeted PhP36.19 Million in Jan-Jun 2009 and PhP51.69 Million in RY 2010. Forecast annual expenditure then rises progressively to reach PhP56.81 Million in RY 2014. We recommend that all expenditures be adjusted to reflect a base annual expenditure of PhP51.59 Million.

This adjustment is shown in Table 5.14

Table 5.14: Adjustment to Forecast Meters, Instruments and Metering Transformers Refurbishment Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	36.19	51.69	52.53	53.95	55.39	56.81
Recommended Expenditure	25.85	51.69	51.69	51.69	51.69	51.69
Adjustment	(10.31)	-	(0.84)	(2.26)	(3.70)	(5.12)

The impact of these adjustments on VECOs overall residual CAPEX forecast is shown in Table 5.15 and Figure 5.6.

Table 5.15: Impact of Adjustments on Residual Refurbishment CAPEX Forecast (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
VECO forecast	73.37	87.34	89.08	92.35	97.85	105.23
Adjustments						
Transformers (Table 5.10)	(0.92)	-	(0.31)	(0.42)	(0.52)	(0.52)
Overhead conductors and devices (Table 5.11)	(0.96)	-	(0.05)	(0.14)	(0.24)	(0.34)
Streetlights and Signal Systems (Table 5.12)	-	-	(2.05)	(5.15)	(9.40)	(14.62)
Structures and improvements – non network (Table 5.13)	(14.98)	(1.50)				
Meters, instruments and metering transformers (Table 5.14)	(10.31)	-	(0.84)	(2.26)	(3.70)	(5.12)
Recommended Forecast	46.20	85.84	85.83	84.38	83.99	84.63

Figure 5.6: Comparison of VECO and Recommended Residual Refurbishment CAPEX Forecast

