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VICTORIAS ENERGY EFFICIENCY AND COGENERATION PROJECT
FINAL REPORT

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Mark P. Dvorsky 11/30/98
Office of Intellectual Property Counsel
DOE Field Office, Chicago
Date

October 31, 1998

By

ECONERGY INTERNATIONAL CORPORATION
3825 IRIS AVENUE, SUITE 350
BOULDER, COLORADO 80301

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Table of Contents

1. Executive Summary	1
1.1 Summary of Carbon Emissions Reductions	2
2. Background Information on Victorias Milling Company.....	3
2.1 Structure of the Company	3
2.1.1 Current Financial Situation	3
2.2 Facilities.....	4
2.3 Raw Sugar Operations	4
2.3.1 Cane Procurement and Handling	8
2.3.2 Milling and Bagasse Production	8
2.3.3 Boiling House	9
2.3.4 Steam Demand.....	9
2.3.5 Electricity Demand	10
2.4 Refining Operations.....	11
2.4.1 Steam Demand.....	11
2.4.2 Steam Generation.....	11
2.4.3 Power Generation.....	11
2.4.4 Water Supply: Condensate and Cooling Systems.....	14
2.4.5 Bagasse Handling and Storage.....	14
3. Methodology Used in Determining Carbon Offsets	15
3.1 Carbon Accounting	15
3.2 Baseline or Reference Cases for Carbon Offset Projects.....	18
3.3 References.....	22
4. Victorias Baseline and Project Cases.....	23
4.1 VMC Baseline.....	23
4.2 Assumptions Used in Characterizing the Base and Project Cases.....	23
4.2.1 Carbon Intensity Calculations.....	24
4.3 Baseline Analysis Results	27
4.4 Fossil Fuel.....	27
4.5 Electrical Energy.....	27
4.6 Phase 1: Energy Efficiency (EE) Project.....	28
4.6.1 EE Base Case Description	28
4.6.2 EE Project Case Description.....	29
4.7 Phase 2: Cogeneration Project	32
4.7.1 Cogeneration Base Case Description.....	32
4.7.2. Cogeneration Project Case Description	32
5. Project Case	34
5.1 Benefits from Phase 1 Energy Efficiency	34
5.2 Benefits from Phase 2 Cogeneration.....	34
5.3 Option 3	35
5.3.1 Capacity and Generation.....	35
5.4 Project Case Carbon Emissions Estimates.....	39
5.5 Net Emissions or Carbon Offset Estimates.....	39

6.	Monitoring & Verification Protocol	41
6.1	Phase 1: Energy Efficiency Project.....	41
6.2	Motivation and Framework for the M&V Protocol.....	41
6.2.1	Projected vs. Actual EE and Base Case Analysis	43
6.2.2	Basic M&V Protocol Outline.....	45
6.2.3	Detailed M&V Protocol Outline.....	48
6.3	References.....	55
6.4	Phase 2: Cogeneration Project	56
6.4.1	Monitoring & Verification for Phase 2	56
7.	NGOs	57
8.	Host Country Acceptance	58
9.	Data Collection	59

List of Figures

Figure 1.	Location of Facilities at Victorias Milling Company.....	6
Figure 2.	Victorias Mill Photographs.....	7
Figure 3.	Existing Boiler and Power House Configuration	13
Figure 4.	Utility CO ₂ Reduction: Cost Analysis.....	19
Figure 5.	Example Utility CO ₂ Emission Profile.....	20
Figure 6.	Base Case Fuel Consumption and Energy Demand.....	29
Figure 7.	Expected Fuel and Energy Demand Reduction.....	30
Figure 8.	Option 3 On-season	37
Figure 9.	Option 3 Off-season	38
Figure 10.	Hypothetical Projected vs. Actual Carbon Emissions.....	44
Figure 11.	Establishing Base Case Conditions in the M&V Protocol	46
Figure 12.	Establishing Project Case GHG Reductions in the M&V Protocol	47

List of Tables

Table 1.	Parameters for Calculation of Net Carbon Storage by Project Classification ...	17
Table 2.	Parameters for Calculation of Carbon Storage by Reference Land-Use Category	18
Table 3.	Carbon Content of Fossil Fuels	18
Table 4.	Load and Capacity Expansion Plan for the Visayas.....	25
Table 5.	Carbon Intensity Calculations for Visayas Power Plants	26
Table 6.	Historical Energy Consumption at Victorias	27
Table 7.	Baseline Carbon Emissions for Victorias	28
Table 8.	Energy Efficiency Modifications to Reduce GHG Emissions.....	31
Table 9.	Summary of Cogeneration Project Generation.....	36
Table 10.	Project Case Carbon Emissions	39
Table 11.	Performance Comparisons and Measurements Required for Monitoring and Verification in Phase 1.....	41

1 Executive Summary

This report describes a two-phase energy project currently contemplated for joint implementation at the Victorias Milling Company (VMC), a large sugar mill and refinery on the island of Negros in the Visayas region of the Philippines. This initiative constitutes the first effort to implement a combined Energy Efficiency (EE) and cogeneration facility at a sugar mill in the Philippines and has the potential to become a model for other such activities throughout the islands. Phase I is an EE project which involves installation of equipment to reduce steam and electricity demand in the factories. The EE phase is expected to reduce or eliminate VMC's fossil fuel consumption, which will have a direct and substantial impact on carbon emissions. The cogeneration component of the project – Phase II, will involve retrofitting and increasing the capacity of the steam and power generation systems, and selling power to the grid. By increasing efficiency and output, the cogeneration project will allow the factory to use only bagasse (sugar cane fiber waste) as fuel for energy needs. The cogeneration project will also eliminate VMC's electricity purchases and supply additional power for the island, which will offset generation capacity expansion on the island and in the Visayas region.

The key objectives established at the outset of this project were to provide comprehensive analysis of the greenhouse gas aspects of the project in order to receive accreditation from the U.S. Initiative on Joint Implementation, and to further investigate project feasibility. The approach undertaken in this effort has provided important insights regarding the efficacy of energy efficiency measures and bagasse-fired cogeneration in general, particularly for less modernized sugar mill and refinery operations.

The report also provides an overview of the facilities and operations at VMC and relevant information about VMC's structure and current financial status. That information provides a basis for understanding both the opportunities for energy efficiency improvements and cogeneration, and important insights related to project feasibility.

Progress on the project itself has been stalled due to a major financial crisis at Victorias and in the Philippines in general in the past year. Because of uncertainties regarding the nature and scale of ongoing operations at Victorias, along with uncertainties regarding the future ownership of the company, the project is not being actively developed at the moment. However, the basic designs for energy efficiency and cogeneration, along with other preliminary work, has been completed and therefore when the financial position of the company becomes clear, the project may deserve renewed attention. For these reasons as well, progress on gaining host country acceptance has been stalled and will be renewed when the project goes into active development again. To date, EIC has briefed the Department of Environment and Natural Resources in the Philippines on the project; they will be the decisive agency when the project is formally submitted.

Further, we include a comprehensive discussion of both the methodology used for the "carbon accounting" of the project, and the actual base case and project case emission

estimates for Phases 1 and 2. Finally, the report also presents a unique monitoring and verification (M&V) protocol that provides a useful model for energy efficiency and demand-side management (DSM) projects as well as cogeneration projects everywhere.

1.1 Summary of Carbon Emissions Reductions

The analysis of the baseline and project cases for the Victorias projects showed a net annual carbon emissions savings of 54,593 metric tons of carbon equivalent. The equations showing how this was derived are shown in Section 5.5. The carbon savings will result from two primary activities:

- 1) Reduction of steam consumption in the sugar mill and refinery, achieved through implementation of energy efficiency and conservation measures, and resulting in direct reduction of fossil fuel consumption (fuel oil);
- 2) Increased production of electrical energy from bagasse, resulting in:
 - a) Elimination of diesel fuel requirements (for generation of on-site electricity);
 - b) Elimination of purchases of electricity from the grid; and
 - c) Export (sale) of bagasse-based electricity from Victorias to the grid.

These two components are described throughout this report as Phase 1 Energy Efficiency and Phase 2 Cogeneration. However, these two components are closely inter-related, as the reduction of steam consumption in the factories allows not only for the reduction of fuel oil consumption, but also allows the cogeneration plant to use more steam for generating electricity and thus it can increase exports. Likewise, the cogeneration plant, through more efficient production and use of high-pressure steam, allows for more efficient use of bagasse fuel and thus contributed to the elimination of fossil fuel consumption. It is quite difficult to precisely compartmentalize the two phases and attribute emissions savings to each, because of the inherent symbiosis involved. The original distinction was based more on commercial reasons (to finance the two projects separately) and thus it has remained so in this report.

2 Background Information on Victorias Milling Company

VMC operates the largest raw sugar mill and refinery in the Philippines. The industrial complex is located near Bacolod City on Negros, in the central Visayas region of the country. The sugar factory has a manufacturing capacity of about 12,000 metric tons (mt) per day of raw sugar. The company also has a sugar refinery, with a peak capacity of 1,250 mt per day refined sugar output. Annual cane processed is about 2.5 million mt, which is used in the manufacture of raw sugar. Cane is supplied to the mill on a year-round basis.

2.1 *Structure of the Company*

Victorias was founded in 1919 and was operated as a privately held company until 1993, when it began trading on the Philippines stock exchange. However, it recently has been delisted due to its financial condition.

The current Chairman and Chief Executive Officer of the company is Manuel Mañalac, who was asked to become CEO in 1997 when financial problems overtook the company. Mañalac owns a stock brokerage company and had become a major shareholder of Victorias.

2.1.1 Current Financial Situation

Victorias is currently in the Philippine equivalent of "Chapter 11", and its creditors exercise control of the company's operations. In February 1997, the management disclosed during the annual shareholder's meeting that the company would not be able to service the large amount of debt it had taken on in the past few years. Most of the debt was taken on to pay for factory improvements – such as a new Walkers milling tandem – and other, non-core business operations such as the construction of a company-owned golf course. These investments were made at a time when the sugar industry in the Philippines was undergoing difficult times and imported sugar was competing with Philippine sugar. The result was that sales and cash flow were not sufficient to cover debt service.

In the Spring of 1997, Victorias' 26 creditor banks created a creditor committee to oversee the restructuring of the company. The company's total debt is approximately 6 billion pesos (approximately \$150 million at current exchange rates). While the majority is peso-denominated, a sizable portion is in dollars, and the peso depreciation in late 1997 exacerbated the problem of debt service. The creditors and Victorias' new management worked out a six-point restructuring plan in early 1998 to attempt to get the company back on its feet. The plan is as follows:

- I. Operations
 - A. Reduce energy consumption
 - B. Reduce work force
 - C. Shorten operating season

- D. Retire company-owned railroad
- II. Bank Debt Conversion
 - A. Convert 50 percent to equity (3 billion pesos)
- III. Bank Debt Restructuring
 - A. Extend term of remaining debt to 15 years
 - B. Lower interest rate
- IV. Trade Debt Restructuring
- V. New Investor
 - A. Attract new investor to place 500 million pesos (\$12.5 mm)
 - B. May be strategic or financial investor
- VI. Divest Non-Core Assets
 - A. Golf course
 - B. Fiberglass plant
 - C. Swine production
 - D. Others

The plan is proceeding slowly, though several of the items have been completed (mainly operations and asset divestiture). On July 13, 1998, the bidding process to sell 51 percent of the company for 500 million pesos began.

Until the bank debt is converted and restructured and a new investor/owner steps in, it is highly unlikely that any cogeneration project will be able to move forward. It is EIC's intention to follow events closely and present its feasibility study and proposal to the new owners sometime in 1998.

2.2 Facilities

VMC has a large industrial estate that consumes considerable amounts of energy, primarily in its raw sugarhouse and refinery. Other plants, such as a cannery, fiberglass factory, and foundry, consume mostly electrical energy. The foundry, when operating at full capacity, has an approximate load of 2 Megawatts. The main energy consumption in the estate is thermal, in the form of low-pressure steam, which is required for use in the manufacture of sugar.

This section describes the processes and facilities for raw and refined sugar production at Victorias. Figure 1 shows the approximate locations of facilities described in this section (not to scale). Figure 2 shows several photographs of the facilities.

2.3 Raw Sugar Operations

The existing factory is nominally rated at 10,000 tonnes cane per day (tcd), although processing rates for the current production season (1997-1998) vary from 3,500 tcd to 10,700 tcd and average approximately 8,500 tcd. Production rates varied from 4,700 tcd to 10,000 tcd for the 1996-1997 season. These production rates are based on weekly averages and probably understate variations in daily or hourly cane processing rates.

Large variations in processing rates are of concern since they affect cogeneration equipment sizing, bagasse availability and internal sugar factory energy usage.

The general appearance of the plant is fair. Some steam leaks were visible and bagasse dust was pervasive throughout the plant. The arrangement of the seven operating boilers and the three inoperative boilers is poor with three boilers outdoors and the balance indoors.

Figure 1: Location of Facilities at Victorias Milling Company

Figure 2: Victorias Mill Photographs

1. Photo 1 shows the bagasse storage shed, located between the cane handling area and the three outside boilers.

2. Photo 2 is a view from the bagasse shed towards the cane handling area and mills.

3. Photo 3 shows the John Thompson boiler and the stack from the Yoshemine boiler (to the west of the bagasse storage shed).

2.3.1 Cane Procurement and Handling

Cane is currently procured from local planters under the old and still existing system of production sharing. In this system, planters do not sell their crop for cash, but rather provide it to the mills to be processed into sugar. The planters receive a percentage of the final product – usually 60 to 70 percent, and in the case of Victorias it is 65 percent. The planters rarely take physical possession of the sugar but instead receive “quedans,” which are essentially IOUs from the mill to the holder. These are taken to traders, who pay cash to the planters at the going market price.

The system is outdated, inefficient and provides each side with very little incentive to invest capital and improve output and efficiency. On the one hand, the mill does not pay for cane and therefore has low raw material (input) costs; on the other, the model assumes that other production costs (including labor), capital and financing costs, and general, administrative and selling expenses are equivalent to approximately 35 percent of the value of the final product. In manufacturing, these costs are much higher. Therefore millers have difficulty recovering capital costs because their revenue just covers production and overhead, and so are extremely reluctant to invest in plant improvements.

Victorias and other millers have for the past several years been proposing an “Alternative Payment System” which is essentially cash for cane. The idea is moving very slowly and has encountered a great deal of inertia from planters.

The drought conditions in 1998 appear to have caused a reduction in cane availability as well as a reduction in juice quantity and quality. The effects of the drought are expected to be even more severe during the next production season.

Cane is brought mostly by trucks, though in the past a narrow-gauge rail system brought a lot of cane to the mill. The rail system is being taken out of operation in the next two seasons.

Cane handling and preparation are relatively good at Victorias, with several weighing stations, new core sampling equipment (though there is some doubt as to the quality of the sampling procedures and laboratory techniques), and large capacity gantries. Road access to the mill is relatively good.

2.3.2 Milling and Bagasse Production

Victorias currently has three milling tandems, two of which are in operation. The oldest, a 70-year old Corliss engine-driven mill of 2,500 tcd, was retired in 1997. The second mill, a 1961 Farrel mill, crushes 5,000 tcd and is in relatively good condition.

In 1993, Victorias purchased and installed a new Walkers milling tandem with a crushing capacity of 10,000 tons cane per day. The mill turbines take steam at 400 psig. Based on

conversations with Walkers (Australia), it is believed that milling capacity from this tandem alone could be increased to 12,000 tcd. This would allow the milling capacity to match the boiling house capacity, without the use of the Farrel mill.

Factory personnel indicated the need to slow down every week to allow the boiling house to handle the extra low grade load due to low juice purities. During this period they operate the Farrel mill. During normal operation, only the Walkers mill is operated. Factory personnel stated that cane availability could be increased to 17,000 tcd. To achieve such production rates, the factory plans to operate the existing Walkers mill and the existing Farrel mill simultaneously.

2.3.3 Boiling House

The boiling house (where raw juice from the mills is processed into raw sugar) has a capacity of 12,000 tcd. There are four sets of quintuple effect evaporators, and three sets of vacuum pans, including one set of continuous pans. The boiling house equipment is in fair condition, from a processing point of view. From an energy efficiency perspective, some items should be replaced, such as juice heaters. In addition, other low-cost items such as steam traps and new piping (for vapor bleeding in the evaporator stations) should be added in order to improve thermal economy.

2.3.4 Steam Demand

Some of the steam generated is used to drive mill turbines (to crush cane); the balance is used in turbogenerators for electricity production. Because of radically decreasing efficiency in all aspects of production – steam generation in the boiler house, electricity generation in the powerhouse, steam and electricity utilization in the sugar process – VMC no longer is self-sufficient in energy. To supplement bagasse, VMC consumes fuel oil, low-grade coal, and diesel, as well as purchasing electricity from the grid.

Currently the VMC raw sugar-making process is very inefficient, consuming on average 750 kg of steam for each metric ton of cane processed (75% steam-on-cane). By contrast, some of the more efficient mills in Hawaii use about 400 kg of steam for a ton of cane (40% steam-on-cane), and even old mills in India often run at around 50% steam-on-cane. Much of the inefficiency is due to very basic problems such as leakages, inappropriately sized and uninsulated piping, poor heat transfer in juice heaters, and lack of steam traps.

In August of 1997, VMC hired a UK-based consultant, Will Nurse, to improve thermal economy and juice processing in the factory. Recommendations made by Nurse have only been partially completed. Some basic items such as larger diameter piping for low-pressure steam have been installed. In general, there seemed to be little understanding of Nurse's recommendations regarding use of first vapors for raw and refinery pans. To some extent, this has aggravated the condensate quality issue.

2.3.5 Electricity Demand

The raw sugar factory has an electrical demand of about 6 MW at full load, and the refinery demand is approximately 3.4 MW at full capacity. Additional estate demand varies from 1 to 3 MW, depending on operation of the foundry. Some load may be shed, such as from the fiberglass plant, if the assets are sold. In the past five years, VMC has not been able to generate enough electricity to meet its current load, and has been purchasing electricity from VRESCO, the local cooperative. The amount of purchased energy has averaged about 5 million kWh per year. The current price of the electricity is 3.75 pesos/kWh, or about US\$ 0.094/kWh at current exchange rates.

2.4 *Refining Operations*

The refinery uses as feedstock raw sugar produced by the raw sugar house of Victorias and other mills. The current capacity, designated as 25,000 Lkg per day (1,250 metric tons), is rarely utilized at 100 percent. Victorias uses all of its raw sugar in the refinery and also buys raw sugar from other factories. The refined sugar produced is a higher margin product than the raw sugar, and therefore Victorias hopes to maximize the production in the future. It is therefore likely that the refinery will operate after the cane processing season is finished.

2.4.1 Steam Demand

The refinery should be able to operate primarily on the vapors from the raw sugar evaporator station (second vapors). Currently the refinery consumes low-pressure (25 psi) steam from the mill turbines exhaust.

2.4.2 Steam Generation

Currently VMC uses bagasse, bunker oil and coal to generate steam. Steam is generated in any or all of 12 different low-pressure boilers, some of which are more than 50 years old. Steam pressures range from 125 psig (de-commissioned boilers) to 400 psig. Steam generation capacity is 913,000 pph @ 400 psig, and 148,000 pph @ 250 psig. The boiler configuration is shown in Figure 3 below.

The existing boilers are fairly inefficient, probably in the range of 50 to 60 percent. This is evident from the high degree of excess air shown in a recent review of the boilers. The most efficient boilers are likely to be the two John Thompson Australia boilers, each with a capacity of 150,000 pph and pressure of 400 psig. These boilers are about 7 years old. The Yoshimine boiler is also 150,000 pph at 400 psig, and is probably as efficient. Nevertheless, it is unlikely these boilers would be efficient enough to use in a new cogeneration scheme; however, because the pressure matches that of the Walker mill turbines, it may be possible to utilize some of the capacity to directly supply the mills. The alternative is to use more efficient, 850 psig boilers and reduce pressure through a turbogenerator to 400 psi, at which point the steam would pass to the mill turbines.

2.4.3 Power Generation

Power is generated inside the factory in a powerhouse that contains five backpressure steam turbines and four diesel generators. There are two steam turbines with inlet pressures of 400 psig and three smaller turbines with inlet pressures of 250 psig. The total capacity is shown below:

11,000 kW steam turbine @ 400 psig
3,250 kW steam turbine @ 250 psig
2,420 kW from diesel generators

The total capacity of approximately 17 MW is never fully utilized. The average load of the steam turbines combined has been from 8 to 9 MW during the past five years, while the diesels typically produce about 500 kW. Some of the reasons for the low production are: pressure drops in main steam lines; lack of adequate cooling water causes steam turbines to be shut down; blade failure and other problems which reduce efficiency. Some of the steam turbines currently have steam rates of close to 50 lbs./kWh, which is unusually high. In any new cogeneration scheme, it is highly unlikely that any of the existing power generation capacity would be used.

Figure 3: Existing Boiler and Power House Configuration

2.4.4 Water Supply: Condensate and Cooling Systems

Condensate return to the boilers has recently been a problem and raw water has been used on occasion, causing some boiler tube failures. Factory personnel ascribed the problem to the refinery, which uses exhaust steam for refinery pans and condensate for various washing functions. In general, the problem seems to be worsening, and the amount of raw make-up water is increasing. According to one of EIC's engineers, this problem could be mostly solved through an inexpensive but carefully executed vapor bleeding system in the evaporator station.

The cooling system is currently inadequate to meet the factory needs. No cooling tower exists at present. All cooling and make-up water is taken from the Malihao River, which runs through the Victorias estate. During the summer and Monsoon months (March through October), water temperatures in the river are too high to provide adequate cooling. The factory management is currently proposing a diversion canal and cooling tower to supply cooling water to the evaporators, vacuum pans and power house, but believe there will not be sufficient financial resources to do this.

In a new cogeneration project, a cooling tower would be constructed.

2.4.5 Bagasse Handling and Storage

The existing bagasse handling system is poorly designed and inadequate for a new cogeneration plant. Like many of the systems at Victorias, it has been constructed in a random fashion over the years, with additions made as needed. The conveyance system is very convoluted and is manually controlled, resulting in frequent lack of bagasse supply to boilers. As a result, the boiler operators often fire the boilers with bunker oil even when bagasse is available. More than anything, a poor fuel delivery system creates erratic steam production and fluctuations in the furnace temperature, which affect steam temperature and pressure.

The existing storage facility for bagasse is a covered, partially walled area of approximately 150 x 150 meters, or about 22,500 m². At 6 meters high this is about 135,000 m³. Bagasse density (loose) is about 120kg/m³. Storage could be approximately 16,000 mt. However, there is a more land going north (away from the mill) which could provide additional outside storage of up to another 50,000 tons. The shed is located north of the raw sugar factory and adjacent to the Riley 4, Yoshimine and JTA 2 boilers. The planned cogeneration site would be adjacent to the bagasse shed. The location of the storage shed is shown in Figure 1 above.

3 Methodology Used in Determining Carbon Offsets

Investments in carbon emission-reduction projects in developing or transition countries without currently-binding emission reduction obligations require a *carbon-offset* mechanism, under which emitters can potentially receive credit toward their own reduction (Swisher and Masters 1992). This type of mechanism is also referred to as open-market trading, as opposed to permit trading (Swisher et al 1997). The potential certification of carbon offsets based on the emission reductions from such projects will require some standardization of carbon-accounting procedures. Such a procedure must explicitly account for the difference between emissions of energy system or carbon storage in a land-use without the project and the emissions or carbon storage with the project (Swisher 1992).

3.1 Carbon Accounting

The foundation of a credible method for carbon offset accounting, as well as subsequent project monitoring and verification, is a consistent and comprehensive framework for quantifying the carbon emission-reduction benefit of a project. The relevant unit of measurement for carbon emission reductions is the difference between the emissions in the baseline or reference case and the emissions from the project.

Energy-sector emission-reduction measures prevent the emission of a quantity of irretrievable carbon emissions. An energy-sector measure, and its corresponding baseline process, has a finite technical-economic lifetime, during which the annual emissions and potential reductions apply. One can imagine that the required energy service would remain after this lifetime, and that the process and emission reduction measure could be repeated indefinitely into the future.

Once the baseline case has been clearly defined (see below), the carbon accounting for energy supply projects is relatively simple. The net emission reduction (R_{net}) for renewable and biomass energy projects must be compared on the basis of the carbon content of the fossil fuel replaced. The carbon accounting for bioenergy projects must be adjusted for differences in efficiency between the biomass and fossil fuel systems, and fossil fuel used to grow, harvest and transport biomass fuel.

$$R_{net} = E_r C_r - E_p C_p \quad [1.0]$$

where: E_r = Energy produced in base case
intensity of energy in base case

C_r = Carbon

E_p = Energy produced in EE project case

C_p = Carbon intensity of energy in EE project case

Though the Victorias Energy Efficiency and Cogeneration Project is classifiable as an energy project rather than a sequestration (land-use) measure, it involves both direct and indirect greenhouse gas (GHG) abatement. Direct abatement occurs from reduction in energy consumption and thus, fossil fuel emissions that result from energy efficiency measures implemented in Phase 1. The less direct abatement occurs from the substitution of biomass fuels for fossil fuels that occurs in the Phase 2 cogeneration project. The implications of bagasse consumption in lieu of higher carbon-content fossil fuels are best understood by comparing energy projects and land-use (biomass projects in general).

For energy efficiency projects, both the project's baseline and resulting energy and emissions savings are less easily observable, although a great deal of research is being carried out to measure such savings in the context of electric-utility demand-side management (DSM) programs. Emission

reduction measures in the energy sector must be measured relative to baseline values, which are typically uniform annual flows of emissions.

There is a wide range of different types of potential GHG abatement projects in both the energy and land-use sectors. Each type of project is different in terms of the net carbon flows that provide emissions reductions or carbon storage potential. Energy projects generally reduce net emissions by reducing energy demand or replacing fossil fuels with cleaner alternatives. Land-use projects can store carbon in standing natural forest, accumulate carbon in new biomass grown in the project, or accumulate carbon in harvested products that enter long-term storage. In addition, biomass energy plantations can store net carbon in new biomass as well as preventing carbon emissions from fossil fuel use. Project types are classified accordingly in Table 1. Note the complexity of the carbon stocks involved in land-use projects, compared to energy projects.

Table 1. Parameters for Calculation of Net Carbon Storage by Project Classification

<i>Type of Project</i>	<i>Carbon Stock:</i>	<i>Standing Biomass</i>	<i>New Biomass</i>	<i>Harvested Biomass</i>	<i>Soil Carbon</i>	<i>Saved Fossil Energy</i>
Forest reserves/reduce deforestation		+	0	0	+	0
Natural forest management		+	0	+	+	0
Timber plantations/wood products		0	+	+	+	0
Forest/ecosystem restoration		0	+	0	+	0
Agroforestry/social forestry		+	+	+	+	0
Fuelwood farms (non-commercial)		+	+	0	+	0
Dryland restoration (annual crop)		0	0	+	+	0
Biomass commercial energy farms		0	0	0	+	+
Biomass energy plantations		0	+	0	+	+
<i>Solar energy/energy efficiency</i>		0	0	0	0	+

("+" means the carbon stock applies to the project classification, "0" means it does not)

As noted above, terrestrial carbon sinks do not accumulate carbon indefinitely, but approach a limiting value. Thus, the carbon-storage benefit of a carbon sink is a one-time increment in the carbon stock on land. While carbon storage in growing forests is a one-time value limited by the maturation of the forests, production of renewable energy and biomass fuels to replace fossil fuels can reduce carbon emissions indefinitely into the future, provided that biomass energy plantations can be grown and harvested sustainably.

The relationships used to estimate carbon storage in forestry and land-use projects can be applied to the reference case. The relevant carbon storage parameters for possible reference land-use categories are given in Table 2. The biomass and soil carbon densities for these land-use conditions can be estimated as fractions of the natural forest carbon densities in the same climate (Brown et al 1989).

Table 2. Parameters for Calculation of Carbon Storage by Reference Land-Use Category

Reference Land Uses	Carbon Stock	Standing Biomass	New Biomass	Harvested Biomass	Soil Carbon
Pasture/Agriculture		0	0	0	+
Fallow/Shifting Cultivation		0	+	0	+
Secondary Forest		0	+	+	+
(Selective) Logged Forest		+	0	+	+
(Selective) Fuelwood Removal		+	0	0	+

("+" means the carbon stock applies to the land-use category, "0" means it does not)

3.2 Baseline or Reference Cases for Carbon Offset Projects

The baseline emissions are the carbon emissions that are expected to result in the absence of the proposed project. Because carbon offsets represent emission reductions or increases in carbon storage, they can only be measured relative to such a baseline. The definition of the baseline is inherently counter-factual (it will be replaced by the proposed project) and therefore uncertain. The level of uncertainty and credibility of the baseline depends on the type of offset project and the dynamics of the existing energy plan or land-use practice.

In the case of power supply projects, the baseline value C_r (Equation 1.0 above) can be relatively clearly determined from the carbon content of the fossil fuel replaced. The carbon intensity of the energy supplied C_p by the project simply depends on the fuel used. This value can generally be assumed to be zero for renewable energy projects, including sustainably grown bioenergy fuel. Some typical values of common fossil fuels are given in Table 3.

Table 3. Carbon Content of Fossil Fuels

	Carbon content in the fuel tC/GJ	Carbon intensity of electricity tC/MWh
Coal	0.024	0.28
Petroleum	0.020	0.23
Natural Gas	0.014	0.16

*Delivered at a net efficiency of 31%. For higher (lower) efficiencies, the carbon intensity would be proportionally less (greater).

The reference energy system, of course, is not static, especially for rapidly growing energy systems, which offer many energy-efficiency opportunities. The implementation of these options can influence the carbon-intensity of the baseline fuel mix. A rigorous analysis of power-system baseline emissions and potential reductions requires detailed simulation of the system (see Figure 4.) On the other hand, the simplest approaches to the analysis of baseline emissions are to:

- use the average emission rate for the entire system (i.e., total emissions divided by total sales); or
- use the emission rate of the marginal generating plant, multiplied by the energy saved, for each hour of the year.

Figure 4. Utility CO₂ Reduction: Cost Analysis

As a hypothetical example, suppose a utility system relies on hydroelectric power for its base-load generation, coal-fired plants for intermediate-load and some combustion turbines (CTs) for the peak loads (see the left-hand chart in Figure 5). The hydro potential is finished, however, and future base-load plants will be coal-fired. The average emission rate is low, based on the predominance of hydropower (see the right-hand scales in Figure 5). The marginal rate would be higher, based mostly on the coal plants and CTs and partly on hydro for hours where only intermediate and not peak-load plants are run (Swisher 1997).

Figure 5. Example Utility CO₂ Emission Profile

A peak-load management program that shifts peak demand in time, with little effect on total energy sales, would simply affect the operating hours of the CTs and perhaps the intermediate-load coal plants. The resulting emission changes, therefore, would closely resemble the marginal hourly emission rates, weighted according to the share of demand reductions (or increases) achieved in each hour. However, energy-efficiency programs significant enough in scale to change the utility expansion plan would make the marginal emission-rate changes difficult to use for calculating emission changes. This is because the resulting emission change might be savings from a coal-fired plant that would be completely removed from the future generation mix, and that would not resemble the average or the marginal resource at all.

Rigorously defining a baseline case, from which emission reductions would be measured, entails analyzing the existing expansion plan to determine the generating resources that would be replaced by saved electricity, and the emissions from these electricity-supply resources (Figure 4). It would be necessary to determine if planned energy-saving projects would reduce base-load or peak demand sufficiently and with enough reliability to defer or obviate planned capacity expansion. If so, the

deferred or replaced source would become the marginal expansion resource to be used as a baseline, beginning at the time this generating source is planned to enter service.

For projects in the domestic sector where fossil fuel is directly saved or replaced, the emission reduction calculation can be made rather simply following Equation 1.0. In the transportation sector, direct fuel-substitution programs are simple enough, as one can simply insert the carbon content values of the baseline and replacement fuels as C_r and C_p , respectively, in Equation 1.0. Similarly, simple vehicle efficiency programs can directly apply the carbon content values of the baseline fuel (C_r) to the fuel savings to estimate emission savings.

Other transport projects, however, can be more complex. For projects that change the mode or type of vehicle, the values of C_r and E_p are not as simple to estimate. In such cases, it may be necessary to carry out simulation studies analogous to those suggested above with regard to the power sector (see). Because the definition and quantification of transport services is less clear than it is for electric-energy services, this analysis process may turn out to be difficult and ambiguous.

One tangible example of a carbon-offset project baseline is the Ilumex project for efficient lighting in Mexico (Blanc and de Buen 1994). The C_r value for this project was determined by simulating the dispatch of existing power stations in Guadalajara and Monterrey. The result was a mix of oil- and coal-fired generation with a combined carbon intensity of 0.19 tC/MWh. This value was applied to the predicted electric energy savings from the project to estimate the resulting emission reduction.

A more complex example would be a biomass-fired co-generation project under development at a sugar mill in India (Swisher and Renner 1996). In this case, the electricity exported from the project could replace the local utility's marginal supply, which would be coal with carbon intensity of 0.3 tC/MWh. However, the utility historically has been unable to meet demand, and additional power from the co-generation plant could in fact add to needed capacity. In this case the exported energy would more likely replace small diesel generators with carbon intensity of 0.2 tC/MWh.

3.3 References

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4 Victorias Baseline and Project Cases

4.1 VMC Baseline

EIC examined historical energy data from Victorias factory logs to determine energy usage baselines. Once established, these numbers will determine the amount of greenhouse gases that Victorias generates on an annual basis.

GHG emissions from direct firing of fossil fuels is determined by multiplying the carbon content of the fuel by the amount of fuel (weight basis) used. In the VMC case, direct firing of fossil fuels at the plant(s) has historically been in the following forms:

1. Diesel fuel fired in diesel generators to produce electricity. These generators are located near the powerhouse in the raw sugar plant. Victorias currently operates three diesel generators: a 700 kW Sulzer, a 920 kW Man, and an 800 kW Enterprise. These generators are quite old and inefficient. The diesel fuel is procured from one of the three refiners in the Philippines: Caltex, Shell Pilipinas, or Petron.
2. Bunker fuel (No. 6 heavy fuel oil) fired in boilers for production of steam.
3. Coal, mined in northern Negros. This coal is very high in ash and has a low calorific value.

Reductions in fossil fuel emissions from direct firing will result from the Phase 1 energy efficiency project as well as the Phase 2 cogeneration project.

GHG emissions from electric power are based on the carbon intensity of the energy unit consumed. This is determined by a process as described in Section 4. The most straightforward method is to determine the marginal generating plant in the system and use the carbon intensity (or carbon emission factor) for that plant. The carbon intensity will be described in units of mtC/MWh, which describe the ration of carbon, measured in metric tons, to the megawatt-hour produced in the marginal generating plant (on a gross basis).

In the case of Victorias, the specific methodology for determining carbon intensity is described below.

4.2 Assumptions Used in Characterizing the Base and Project Cases

Victorias is located on the Island of Negros in the central part of the region called the Visayas. The Visayas is itself in the central part of the Philippines archipelago, and is comprised of many small islands and several major islands, including Leyte, Bohol, Cebu, Negros, Panay, and Palawan.

Currently, only three of the islands are interconnected with high voltage transmission lines, in the form of 110kV submarine cables. The three connected islands are Cebu, Negros, and Panay. Another cable is currently being laid between Cebu and Leyte, which will effectively connect Cebu, Negros and Panay to the main island of Luzon. A map showing the Philippine national grid, with transmission linkages in the Visayas, is shown on the last page of this report.¹

From the projected load and capacity numbers, it appears that the Visayas have greater reserve margin than both Luzon and Mindanao, throughout the 1997-2010 period. (See Table 4 below for detailed estimates from the National Power Corporation, NPC.) The table shows the ratio of capacity to projected load for each region. Though all three regions are positive (from a planning perspective this

¹ World Bank, Staff Appraisal Report, Philippines Transmission Grid Reinforcement Project, February 20, 1996.

is typical), though in each year the Visayas has a higher ratio than the other two. This implies that the direction of power flow is from the Visayas, not into them. One could argue that an incremental change in the Visayas could influence dispatching of the marginal plant elsewhere, but we think we can safely assume that such effects are second order, and that power used in Visayas is generated in Visayas. (Please note also that the capacity projections for each region are total capacity, not *available* capacity, which would incorporate transmission losses and plant capacity factors. Available capacity will be less than total capacity, and though these numbers could be estimated, it is not necessary for this project.)

Geothermal sources of power in the Visayas have low variable costs, so the marginal dispatch should generally be a fuel-fired plant, and the marginal capacity addition over the long term seems to be fuel-fired as well. Of the fuel-fired plants, those with the highest heat rates (i.e., lowest conversion efficiency) are the coal-fired plants in Cebu.

4.2.1 Carbon Intensity Calculations

Table 5 below shows carbon emission factors or carbon intensity calculations for existing operating fossil plants in Cebu, Panay, and Negros provinces of the Visayas. We exclude plants with unknown status, or plants currently under construction or under evaluation. Heat rate information for the Cebu coal-fired power plants I and II is provided by Preferred Energy Investments of Manila, Philippines. Heat rates for the remaining diesel plants were estimated based on typical values of available technology according to fuel type and age. Finally, the average heat rate value for diesel power barges was assumed to be comparable to those in Regions 4 and 10, for which EIC had quantitative data. EIC compared all estimates to the reported NPC 1996 national heat rate average (11,055 But/kWh) for reference.

Carbon content by weight and heating values for coal and diesel were obtained from Argonne National Laboratory's Center for Transportation Research. Carbon content by weight for bunker fuel was obtained from Perry's Chemical Engineering Handbook, Sixth Edition.

Table 5 shows that calculated carbon intensities for existing diesel plants are about 0.29 metric tons carbon (mtC) per MWh, 0.38 mtC/MWh for coal-fired plants, and 0.25 mtC/MWh for diesel power barges. Total carbon emissions in mtC will depend upon corresponding annual energy sales data for these plants.

Table 4. Load and Capacity Expansion Plan for the Visayas

Year	Visayas Load Projection ¹ (MW)	Visayas Capacity ² (MW)	Ratio of Capacity/ Load	Luzon Load Projection ¹ (MW)	Luzon Capacity Expansion (incr Additions) ¹ (MW)	Luzon Capacity ¹ (MW)	Ratio of Capacity/ Load	Mindanao Load Projection ¹ (MW)	Mindanao Capacity Expansion (incr Additions) ¹	Total Capacity, Mindanao (MW)	Ratio of Capacity / Load
1997	739	1530	2.07	4744		7697	1.62	1130		1643	1.45
1998	832	1630	1.96	5397	600	8297	1.54	1359	97	1740	1.28
1999	955	1890	1.98	6079	500	8797	1.45	1587	377	2117	1.33
2000	1080	1931	1.79	6779	2173	10970	1.62	1822	150	2267	1.24
2001	1254	1963	1.57	7484	750	11720	1.57	2059	150	2417	1.17
2002	1405	2103	1.50	8266	1285	13005	1.57	2321	239	2656	1.14
2003	1556	2432	1.56	9135	900	13905	1.52	2610	300	2956	1.13
2004	1676	2682	1.60	10102	1207	15112	1.50	2930	300	3256	1.11
2005	1796	3082	1.72	11177	1195	16307	1.46	3283	524	3780	1.15
2006	1924	3282	1.71	12373	150	16457	1.33	3673	224	4004	1.09
2007	2051	3382	1.65	13705	300	16757	1.22	4105	300	4304	1.05
2008	2208	3632	1.64	15188	188	16945	1.12	4583	200	4504	0.98
2009	2366	3832	1.62	16842	600	17545	1.04	5112	150	4654	0.91
2010	2536	4132	1.63	18684	960	18505	0.99	5698	300	4954	0.87

¹NPC's Power Demand Forecast and Expansion Plan(1995)²Includes both NPC and BOT projects for years 1997-2005.

Data available only for NPC capacity additions for years 2006-2010.

Table 5. Carbon Intensity Calculations for Visayas Power Plants

Location (1)	Plant Name (2)	Fuel (3)	Heat Rate (4)	Assumed Carbon Content [mtC/ton] (5)	Assumed Heating Value of Fuel [Btu/ton]* (6)	Carbon Intensity [mt C/MWh] (4)*(5)/(6) = (7)	Generation* [MWh] (8)	Carbon Emissions [mtC] (7)*(8) = (9)	Plant Capacity [MW] (10)	Plant Capacity Factor [unit-less] (11)
Cebu (Naga)	Cebu Diesel I IC 1-7	Diesel	11600 ¹	0.87	34,500,000	0.293	81,106	23,725	51.1	0.181
Cebu (Talavera)	Cebu Diesel II IC 1-3	Diesel	11600 ¹	0.87	34,500,000	0.293	31,288	9,152	58.0	0.062
Cebu (Naga)	S1	Coal	11800 ²	0.6	18,837,000	0.376	?	?	50.0	?
Cebu (Naga)	S2	Coal	11800 ²	0.6	18,837,000	0.376	?	?	57.0	?
Cebu (Toledo City)	Toledo Power Corp	Coal	11800 ²	0.6	18,837,000	0.376	515,164	193,627	96.3	0.611
Cebu (Naga)	Naga Coal I	Coal	11817 ³	0.6	18,837,000	0.376	146,777	55,167	50.0	0.335
Cebu (Naga)	Naga Coal II	Coal	11817 ³	0.6	18,837,000	0.376	355,287	133,537	55.0	0.737
Cebu (Naga)	Barge GT 1 & 2	Diesel	10000 ⁴	0.87	34,500,000	0.252	?	?	27.5	?
Cebu (Naga)	GT Turbines 1 & 2	Diesel	10000 ⁴	0.87	34,500,000	0.252	79,901	20,149	55.0	0.166
Cebu (Naga)	Diesel Barge #101	Diesel	10000 ⁴	0.87	34,500,000	0.252	59,982	15,126	32.0	0.214
Cebu (Naga)	Diesel Barge #102	Diesel	10000 ⁴	0.87	34,500,000	0.252	79,363	20,013	32.0	0.283
Cebu (Naga)	GT barge #206	Diesel	10000 ⁴	0.87	34,500,000	0.252	31,673	7,987	30.0	0.121
Panay (Iloilo City)	GT barge #207	Diesel	10000 ⁴	0.87	34,500,000	0.252	95,028	23,964	30.0	0.362
Cebu (Naga)	GT barge #208	Diesel	10000 ⁴	0.87	34,500,000	0.252	46,217	11,655	30.0	0.176
Cebu (Naga)	GT barge #209	Diesel	10000 ⁴	0.87	34,500,000	0.252	72,351	18,245	30.0	0.275
Panay (Iloilo)	Panay Diesel I	Diesel	10000 ⁴	0.87	34,500,000	0.252	51,441	12,972	36.5	0.161
Panay (Capiz)	Panay Diesel II	Diesel	10000 ⁴	0.87	34,500,000	0.252	13,694	3,453	11.0	0.142
Panay (Iloilo City)	Diesel Barge #103	Diesel	10000 ⁴	0.87	34,500,000	0.252	72,835	18,367	32.0	0.260
N/A	GT barge #203	Diesel	10000 ⁴	0.87	34,500,000	0.252	80,741	20,361	30.0	0.307
N/A	GT barge #204	Diesel	10000 ⁴	0.87	34,500,000	0.252	21,455	5,410	30.0	0.082

*Assumes diesel has 128,500 Btu/gal and density of 3,240 g/gal **Source: Preferred Energy Incorporated

¹Source: Kaukauna Electric and Water's Diesel Power Plant. 9/16/97. <<http://www.wppisys.org/kew/diesel.htm>>

²Author's estimate

³Preferred Energy Investments. 1998. Manila, Philippines. Personal Communication.

⁴Based on average of available data on diesel barges for Regions 4 and 10.

4.3 Baseline Analysis Results

Energy consumption at Victorias over the past several years is presented in Table 6 below. These data will be used for the baseline calculations.

Data obtained for crop years 1996-1997 and 1997-1998 were not obtained because of changes in factory management.

Table 6. Historical Energy Consumption at Victorias

Energy	Unit	1991-92	1992-93	1993-94	1994-95	1995-96	Avg.
Bunker	mt	15,715	10,447	17,746	19,930	26,181	18,004
Coal	mt	9,729	7,459	8,617	8,551	5,827	8,037
Diesel	mt	727	968	874	908	826	860
Power Purchased	MWh	5,502	5,122	3,706	4,289	6,220	4,968
Power Generated	MWh	76,596	78,150	81,272	73,534	77,267	77,364
Power Consumed	MWh	82,097	83,271	84,978	77,823	83,487	82,331

4.4 Fossil Fuel

In the past decade, Victorias has used bunker fuel (No. 6 heavy fuel oil) and coal to fire boilers for steam generation for process use. In addition, diesel fuel has been used in diesel generators for direct production of electric power. Although diesel is used for electricity generation, it is considered part of the fossil fuel baseline. This is because the emissions related to diesel generator operation are measured directly from the weight of fuel consumed, multiplied by the carbon content of the fuel. The electric energy baseline is more complex to calculate and is therefore treated separately.

Coal will not be considered part of the baseline because Victorias has decided not to use coal in its boilers in the future. This would be done regardless of the proposed project because of the negative impact on boiler operation, which is a direct result of coal firing. Because this decision is not dependent on the proposed project, it is not considered additional and is therefore eliminated from the baseline calculations.

For bunker fuel and diesel, the averages taken from Table 6 above will be used.

4.5 Electrical Energy

Victorias has averaged about 80,000 MWh of electric energy consumption annually over the past decade. The majority of the electrical load and energy consumption is in the raw sugar and refinery operations, though the balance of the facilities also consumes electricity.

Of the total electric energy consumption, only about 6 percent, or 5,000 MWh, is purchased from VRESCO. It is this additional energy purchased from the grid that forms the electrical energy baseline for the project. Table 7 below shows the baseline carbon

emissions from Victorias, based on carbon emissions factors and actual fuel and electric power consumption.

Table 7. Baseline Carbon Emissions for Victorias

	Fossil Fuel Consumption (mt)	Electricity Generation (MWh)	Marginal Carbon Emission Rate (mtC/MWh)	Carbon Factor (mtC/mt fuel)	Annual Carbon Emissions (mtC)	Cumulative Emissions (mtC)
Total Exported Electricity		-	0.293		-	-
VMC Electricity Purchases		4,968	0.293		1,453	29,065
No. 6 Fuel Oil	18,004			0.873	15,710	314,206
Diesel Fuel	860			0.870	748	14,964
Total					17,912	358,235

4.6 Phase 1: Energy Efficiency (EE) Project

As noted above in Section 2.4.1, the steam demand at Victorias is currently and has been for some time far higher than industry norms. The result of this high demand is additional cost and additional carbon emissions. This is because Victorias is not able to operate on bagasse fuel alone, and is required to purchase bunker fuel, coal and diesel fuel to produce steam and electricity for its milling and refining operations.

The first step in the proposed JI project is to reduce steam demand at the raw sugar and refinery plants.

4.6.1 EE Base Case Description

As noted in Section 2.4.2, VMC produces raw cane sugar and also has a sugar refinery that supplies nearly half of the refined sugar of the Philippines. To produce raw sugar and refined sugar, VMC currently uses a combination of bagasse (cane fiber remaining after sugar cane is crushed), No. 6 heavy fuel oil (bunker), and low-grade coal to generate steam for process and some electrical production; diesel is used for electricity only. Most of the power consumed by VMC is generated on site, from steam turbines and diesel generators. VMC's on-site electricity generation is not quite sufficient to meet its total demand, however, and some electricity is purchased from the local electric cooperative, VRESCO.

The Phase 1 component involves installation of equipment to reduce overall steam and electricity demand in the factories. This will reduce or eliminate fossil fuel consumption and some electricity purchases. Existing process equipment is relatively old and poorly maintained. Likewise, steam and power generation equipment is generally out-dated and

inefficient, resulting in significant losses. Consumption of energy in both factory and refinery are therefore high, in comparison to other similar mills, which usually have Steam on Cane ratios (steam usage per unit cane crushed) of 50%. By contrast, VMC averages about 70%.

The sugar factory has a processing capacity of 12,000 metric tons (mt) of cane per day or roughly 2.5 million tons annually, and a nominal rating of 10,000 mt of cane per day. Growers both within the Vicmico district and beyond supply cane to the mill on a year-round basis. The mill and refinery consume approximately 700,000 pounds per hour (pph) of process steam at peak, and more than 10 MW of power.

The current approximate fuel and energy consumptions at VMC are: 8,000 metric tons/yr (mt) coal; 19,000 mt/yr bunker; 900,000 liters/yr diesel; and 70 million kWh/yr (5 million kWh/yr are purchased from VRESCO). Efficiency improvements should reduce or eliminate existing usage of fossil fuels.

Figure 6. Base Case Fuel Consumption and Energy Demand.

4.6.2 EE Project Case Description

Figure 7 illustrates the expected energy demand and fossil fuel reductions that will result from the Phase 1 EE project.

Figure 7: Expected Fuel and Energy Demand Reduction

Finally, Table 8 illustrates the specific Energy Efficiency Measures (EEMs) that will be undertaken in Phase 1, and the resulting effects on fuel consumption and energy demand.

Table 8. Energy Efficiency Modifications to Reduce GHG Emissions

Modification	Result	GHG Effect	Fuel/ Load
Increase pipe diameter from boilers to powerhouse.	Reduce pressure drop; increase power output.	Reduce fossil fuel intake.
Increase pipe diameter from powerhouse to refinery.	Reduce pressure drop; save steam.	Reduce thermal demand and thus fossil fuel intake.
Improve piping insulation.	Reduce heat loss; increase power output.	Reduce fossil fuel intake.
Economizers for two JTA boilers.	Increase feedwater temperature.	Reduce fossil fuel intake.
Steam traps on heat exchangers.	Improve process steam quality.	Reduce thermal demand and thus fossil fuel intake.
Heat removal for high temperature cooling water.	Reduce downtime for steam turbines.	Reduce fossil fuel intake.
Energy recovery equipment for depressurizing steam.	Reduce pressure losses through valves.	Reduce thermal demand and thus fossil fuel intake.
Fix evaporator inefficiencies.	Reduce steam consumption.	Reduce thermal demand and thus fossil fuel intake.
Thin juice heaters.	Pre-heat juice before evaporators.	Reduce thermal demand and thus fossil fuel intake.
Raw juice filters.	Reduce large particles to heaters and clarifiers.	Reduce thermal demand and thus fossil fuel intake.
Clarified juice filters.	Reduce incondensibles to evaporators.	Reduce thermal demand and thus fossil fuel intake.
Efficiency improvements at auxiliaries.	Reduce boiler parasitic load.	Reduce electric demand and thus fuel intake.
Repair steam leaks throughout plant.	Reduce steam production.	Reduce thermal demand and thus fossil fuel intake.
Downseals for evaporators.	Increase juice contact with heating tubes; improve heat transfer.	Reduce thermal demand and thus fossil fuel intake.

Thermal demand reduction

Bagasse, bunker, coal reduction

Electric demand reduction

Diesel fuel reduction

4.7 *Phase 2: Cogeneration Project*

The cogeneration component of the project -- Phase 2 -- will involve retrofitting and increasing the capacity of the steam and power generation systems, and selling power to either VRESCO, or the NPC. Since the power generated on site by VMC is currently not sufficient to meet its own demand, the balance is ultimately supplied by a combination of diesel and geothermal sources from within the Negros grid. Feasibility analysis conducted for the cogeneration phase suggests that the most economically attractive project option is a 40 MW plant that runs strictly on bagasse (project options considered included 25 MW and 40 MW plant capacities, with and without fuel oil supplementation during the off-season). The cogeneration project will eliminate VMC's electricity purchases and supply additional power for the island, which will offset generation capacity expansion on the island and the region.

VMC currently purchases between 7 and 10 percent of its annual 51 GWh of energy from VRESCO. Thus, roughly 5 million kWh in electricity purchases will be eliminated, and the associated carbon emissions attributable to fossil-fueled generating sources within the regional grid will be offset.

4.7.1 Cogeneration Base Case Description

The base case for Phase 2 can be summarized as follows:

Base Case: VMC purchases roughly 5 million kWh of energy each year and generates the remainder of their electricity needs on-site with bagasse and diesel. The 5 million kWh are purchased from the Visayas grid, which is supplied by a combination of diesel, coal, geothermal and hydroelectric generating resources.

4.7.2 Cogeneration Project Case Description

In order to determine the incremental GHG reductions truly attributable to elimination of VMC's electricity purchases and the initiation of power exports to the grid, Phase 2 required a rigorous analysis of the power flows within the interconnected Visayas grid, identification of the base-load and marginal generating resources, the fuels and carbon intensities associated with those plants, and plant heat rates and capacity factors. Further, the analysis required investigation of NPC's future resource plan in order to project expected GHG abatement over the project's lifetime.

The project case assumptions for Phase 2 are summarized:

Project Case: Both VMC's electricity purchases from the grid and on-site diesel consumption are eliminated. Thus, the 5 million kWh of energy previously supplied by the marginal resources within the regional grid, plus the additional power available for export during a significant portion of the year (approximately 40 MW) are now produced strictly from bagasse.

As noted in the discussions of baseline determination and carbon cycle analysis, it appears that the Visayas have greater reserve margin than Luzon, and much greater than Mindanao throughout the 1996-2010 period. Thus, the direction of power flow is from, rather than toward the Visayas. This, in turn implies that power consumed in Visayas is also generated there. Those observations simplify the carbon cycle analysis significantly, since they essentially mean that analysis of the impact of VMC's exported power can be limited to the Visayas grid.

Analysis within the grid consisted of identification of existing and planned generating resources and their dispatch patterns throughout the planning period. Those plants, their fuel sources, heat rates, capacity factors, and carbon intensities as identified in Table 5, were analyzed to determine the marginal resources within the Visayas. As the coal, hydro, and geothermal plants are assumed to be the base-load plants, the marginal resources within the regional grid were determined to be the diesel units, with carbon intensities of 0.293 mt carbon per MWh.

5 Project Case

5.1 *Benefits from Phase 1 Energy Efficiency*

The steam and electrical demand of the VMC facilities are taken from mass and energy balances prepared by Will Nurse, VMC's consulting engineer. Assumptions for cane crushed and bagasse produced are also taken from these balances. Current and historical consumption of steam in the factories has been very high. According to Victorias records, often as high as 75 percent steam on cane but usually averaging around 70 percent. Much of the excess steam usage is related to simple leakages and other losses, and also the lack of simple equipment such as steam traps and desuperheaters (instead of pressure reducing valves). According to Will Nurse, achievement of 50 percent steam on cane (and self-sufficiency with bagasse with current configurations) is feasible with minimal investment. Improvements would include plugging of leaks, replacement and insulation of piping, installation of desuperheaters and new juice heaters, and use of vapor bleeding in the evaporator stations.

5.2 *Benefits from Phase 2 Cogeneration*

The new cogeneration generating capacity is expected to be 40 MW peak capacity, with about 205 GWh gross generation annually. The mill and its associated companies will purchase about 51 GWh and the distribution company (grid) will purchase about 125 GWh. Average demand from the industrial estate (mainly raw sugar and refinery) during the season is approximately 10 MW.

The mill and refinery will consume approximately 282 mt per hour of process steam after energy efficiency improvements are made. Some steam produced from bagasse will be dedicated for use in mill turbines, and will therefore not generate electric power. Current steam generation is at pressures of 400 psig and 600°F. New equipment will generate steam at 850 psig and 825°F. The boiler selection has not yet been made, and will be based on cost-performance trade-offs. Steam turbines will require an exhaust pressure of about 25 psig and 267°F temperature, for process requirements in the sugar boiling house.

In preparing cogeneration design options for the Victorias mill, EIC analyzed the existing arrangement and built upon that. Some of the options are not described here because they were rejected early in the process as least desirable or not feasible. These included the first option, which considered using five of the existing boilers and adding one new 150 mt boiler. The next option was to replace all boilers and add three new 150 tonne boilers for a total capacity of 450 mt/hr, and a 60 MW turbine. This option would have presented problems in terms of finding an off-take for the exported power, and so it was rejected. The option chosen most desirable is called Option 3.

5.3 Option 3

5.3.1 Capacity and Generation

Option 3 would consist of adding two new boilers of 175 mt/hr steam at 850 psig and 825° F each. The boiler would fire bagasse only. None of the existing boilers and turbines would be used.

The new boilers would supply steam at high pressure directly to one new steam turbine of 40 MW capacity. The turbine would be of condensing-extraction type, with one extraction at 400 psi for use in the Walkers mill turbines and 25 psi for process steam usage. During the crushing season this turbine would generate approximately 41.0 MW of power. The power plant itself will have a load of approximately 5 MW. It is estimated that the refinery will have a load of 3.4 MW and the raw sugar process will have a load of 6.0 MW. This provides a net available capacity for export (3rd party sales) of 26.6 MW.

Total gross generation during the season would be 162.5 GWh, and the net generation exported would be 105.5 GWh.

During the off-season the power plant would operate at 10.2 MW gross capacity based on the availability of bagasse, with 2.0 MW of parasitic load and 3.4 MW of refinery load. Net available generation capacity for export would be 4.8 MW. Total gross generation would be 42.3 GWh, while net exported generation would be 19.9 GWh.

Based on these scenarios, annual gross generation would be 204.8 GWh, and net exported generation would be 125.4 GWh. Annual capacity factor for Option 3 would be 58 percent (total generation/8760*40 MW). Table 9 summarizes the generation from the project case.

In Option 3, only bagasse will be consumed. The total bagasse fired would be 548,000 mt during the season and 116,100 mt during the off-season for a total of 664,100 mt. Figure 8 below shows the on-season configuration of the cogeneration plant, while Figure 9 shows off-season generation.

Table 9. Summary of Cogeneration Project Generation

Option	3
New HP Boiler Capacity (mt/hr)	350
Gross Nameplate Capacity (MW)	40.0
On-Season Generation	
Days operation (@22 hours/day)	180
On Season Capacity (MW)	41.0
Power Plant Load (MW)	5.0
Raw Factory Load (MW)	6.0
Refinery Load (MW)	3.4
On Season Net Export (MW)	26.6
Gross Generation (GWh)	162.5
VMC Consumption (GWh)	37.1
Net Exported Generation (GWh)	105.5
400 psig Steam (mt/hr)	0
850 psig Steam (mt/hr)	350
Bagasse Consumption (mt x 10 ³)	548.0
Off-Season Generation	
Days operation (@24 hours/day)	173
Off-Season Capacity (MW)	10.2
Power Plant Load (MW)	2.0
Raw Factory Load (MW)	0
Refinery Load (MW)	3.4
Off Season Net Export (MW)	4.8
Gross Generation (GWh)	42.3
VMC Plant Consumption (GWh)	14.0
Net Exported Generation (GWh)	19.9
400 psig Steam (mt/hr)	0
850 psig Steam (mt/hr)	72
Bagasse Consumption (mt x 10 ³)	116.2
Total Annual Gross Generation (GWh)	
	204.8
Total Annual Net Exported Generation (GWh)	
	125.4
Annual VMC Consumption (GWh)	
	51.0
Capacity Factor (%)	
	58%

5.4 Project Case Carbon Emissions Estimates

The table below shows a summary of results for the Phase 2 Cogeneration project, where electricity purchases are eliminated and electricity exports to the grid are made. The marginal carbon emissions rate is used to calculate total carbon offsets. An assumed project life of 20 years is used to estimate cumulative emissions offsets. In the following section, the calculations are shown in detail.

Table 10. Project Case Carbon Emissions

	Fossil Fuel (mt)	Electricity Generation (MWh)	Marginal Carbon Emission Rate (mtC/MWh)	Carbon Factor (mtC/mt fuel)	Annual Carbon Emissions (mtC)	Cumulative Emissions (mtC)
Total Exported Electricity		-125,400	0.293		-36,682	-733,645
VMC Electricity Purchases		0	0.293		0	0
No. 6 Fuel Oil	0			0.873	0	0
Diesel Fuel	0			0.870	0	0
Total					-36,682	-733,645

5.5 Net Emissions or Carbon Offset Estimates

To calculate net emission savings, we will use Equation 1.0, as shown in Section 3:

$$R_{\text{net}} = E_r C_r - E_p C_p$$

To simplify, we will apply the formula to each type of energy used:

- Electrical
- Bunker fuel
- Diesel fuel

1. For electrical energy, the savings are as follows:

E_r = electric energy produced in base case, or 4,968 MWh purchased from grid

C_r = Carbon intensity of energy in base case, or 0.293 mtC/MWh

E_p = Energy produced in project case, or 0 MWh purchased, *minus* the electricity exported to the grid from bagasse production, 125,400 MWh, or -125,400 MWh.

C_p = Carbon intensity of energy in project case, or 0.293 mtC/MWh

Therefore:

$$\begin{aligned}
 R_{\text{net}} &= (4968 * 0.293) - ((0 - 125400) * 0.293) \\
 &= 1,453 - (-36,682) \\
 &= \mathbf{38,135 \text{ mtC}}
 \end{aligned}
 \tag{2.0}$$

Therefore the net annual emissions savings from electricity is 38,135 mt of carbon.

In this calculation, the exported electricity (125,400 MWh) is subtracted from zero because Victorias at this point is providing electricity with zero carbon intensity; one could say that Victorias has a negative consumption of grid electricity.

2. For bunker fuel, the savings are as follows:

$$\begin{aligned}
 E_r &= \text{bunker fuel consumed in base case, or 18,004 mt} \\
 C_r &= \text{Carbon intensity of energy in base case, or 0.873 mtC/mt fuel} \\
 E_p &= \text{bunker fuel in project case, or 0 mt.} \\
 C_p &= \text{Carbon intensity of energy in project case, or 0.873 mtC/mt fuel}
 \end{aligned}$$

Therefore:

$$\begin{aligned}
 R_{\text{net}} &= (18004 * 0.873) - (0 * 0.873) \\
 &= 15,710 - \\
 &= \mathbf{15,710 \text{ mtC}}
 \end{aligned}
 \tag{3.0}$$

2. For diesel fuel, the savings are as follows:

$$\begin{aligned}
 E_r &= \text{diesel fuel consumed in base case, or 860 mt} \\
 C_r &= \text{Carbon intensity of energy in base case, or 0.870 mtC/mt fuel} \\
 E_p &= \text{diesel fuel in project case, or 0 mt.} \\
 C_p &= \text{Carbon intensity of energy in project case, or 0.870 mtC/mt fuel}
 \end{aligned}$$

Therefore:

$$\begin{aligned}
 R_{\text{net}} &= (860 * 0.870) - (0 * 0.870) \\
 &= 748 - 0 \\
 &= \mathbf{748 \text{ mtC}}
 \end{aligned}
 \tag{4.0}$$

Total emissions savings from the Phase 1 and Phase 2 projects are therefore the sum of equations 1, 2 and 3:

$$38,135 + 15,710 + 748 = \mathbf{54,593 \text{ mtC}}
 \tag{5.0}$$

6 Monitoring & Verification Protocol

6.1 Phase 1: Energy Efficiency Project

As the Phase 1 EE project will result in reduced thermal (steam) and electrical demand requirements, it is expected that all of the fossil fuel consumption on-site can be eliminated. The net greenhouse gas (GHG) savings will be realized from that fossil fuel elimination. Energy savings can be assessed by characterizing a "base" case, and then measuring energy use after the EE project is implemented (the "project" case), as discussed in Sections 3, 4, and 5. Energy savings is then multiplied by the appropriate carbon intensity for the associated fuels eliminated or reduced to determine net GHG reduction. Table 11 characterizes the comparisons that are needed to assess the performance of energy projects and which quantities must be measured. For the EE project case, the monitoring needs are highly project-specific, depending on the type of project. For this type of project involving elimination of fossil fuels (leaving only use of a renewable fuel source), one can generally assume the net carbon intensity associated with combustion of the bagasse in the EE project case is zero.

Table 11. Performance Comparisons and Measurements Required for Monitoring and Verification in Phase 1.

Case	Comparison	Required Measurements
Base	Fuel or electric energy end-use	Energy end-use and carbon fuel intensity
EE Project	More efficient end-use technology	Change in energy use

6.2 Motivation and Framework for the M&V Protocol

As proposed in the Work Plan submitted on September 19, 1997, the M&V Protocol for this project is based in part upon the U.S. Department of Energy's "North American Energy Measurement and Verification Protocol" (NEMVP), published in 1996. The NEMVP is well suited for single buildings and facilities and is intended to introduce procedures that allow buyers, sellers and financiers of energy projects to quantify energy efficiency measure (EEM) performance and energy savings, and allocate various risks associated with achieving energy cost savings to either the buyer or seller of the project. Additionally, the NEMVP can provide the basis for structuring Guaranteed Savings, Shared Savings, and Pay-From-Savings contracts for energy projects.

The motivation for the M&V Protocol developed for this work is first and foremost to meet the monitoring, reporting, and verification requirements set forth for USIJI-sanctioned projects. As such, its primary aim is to ensure that the Phase 1 EE Project results in sustained GHG reductions (below the base case) throughout the project life span by conducting field validation measurements and reporting on the results at prescribed intervals. Its overall framework,

however, is consistent with and complementary to the M&V objectives of energy saving projects conventionally carried out by energy service companies (ESCOs).

The USIJI criteria stipulate that a project submission must contain "...adequate provisions for tracking the greenhouse gas emissions reduced or sequestered resulting from the project, and on a periodic basis, for modifying such estimates and for comparing actual results with those originally projected." Further, the USIJI Guidelines for Project Proposals require the filing of an annual report that includes "...monitoring data and analysis on emissions reduced or sequestered...significant environmental impacts/benefits...significant economic and other impacts/benefits."

This M&V Protocol is a hybrid format that incorporates the fundamental principles of USIJI's guidelines for Energy Demand Projects, and those of Options B (*Savings Verification, End-Use Retrofits - Measured Capacity, Measured Consumption Approach*) and C (*Whole Building or Main-Meter Measurement Approach*) of the NEMVP.

Applicable Elements of NEMPV Options B & C: As noted, NEMVP is targeted toward the verification and tracking of energy savings for typical ESCO projects carried out in single buildings or facilities. However, of the three options for developing M&V Protocols contained therein, Options B and C have some components that are very suitable to the VMC EE Project.

- Option B: Savings Verification, End-Use Retrofits - Measured Capacity, Measured Consumption Approach:

Verification techniques for Option B are designed for projects where long-term continuous measurement of performance is desired. Under Option B, individual loads are continuously monitored to determine performance, and this measured performance is compared with a baseline to determine savings. Option B M&V techniques provide long-term persistence data on the operation and performance of the EEMs. This data can be used to improve or optimize the operation of the equipment on a real-time basis, thereby improving the benefit of the retrofit. Option B also relies on the direct measurement of affected end uses.

- Option C: Whole Building or Main-Meter Measurement Approach:

Verification techniques for Option C determine savings by studying overall energy use in a facility and identifying the effects of energy projects from changes in overall energy use patterns. Option C methods are required when measuring interactions between energy systems is desired, and when determining the impact of projects that cannot be measured directly, such as insulation or other envelope measures, is necessary.

Applicable Elements of the USIJI Protocol: USIJI guidelines provide the basic design elements of M&V protocols for energy projects. The protocol must identify:

- Items to be monitored;

- Monitoring methods -
 - ◊ Trend Monitoring: evenly spaced time series;
 - ◊ Implementation Monitoring: assessment of whether activities are implemented as planned;
 - ◊ Effectiveness Monitoring: evaluation of whether specified activities are effective;
 - ◊ Validation Monitoring: validation of model assumptions;
 - ◊ Compliance Monitoring: determination of compliance with established criteria;
- Schedule; and
- Responsible parties.

For Energy Demand Projects in particular, USIJI recommends that the performance of all EEMs over their lifetime be measured, and that variables affecting energy demand, such as outdoor/indoor temperatures, conditioned floor space, and changes in production or staffing levels be monitored. However, the selection of items to be monitored does not necessarily need to include every sink or source of GHGs in order to be sufficiently complete. Rather, USIJI suggests that the largest, most uncertain, and highly variable items should be selected for monitoring.

6.2.1 Projected vs. Actual EE and Base Case Analysis

After implementation of the proposed Energy Efficiency Measures at VMC, it is likely that actual GHG emission levels will differ from those projected over the EE Project life span. GHG levels will be affected by many parameters unrelated to the EEMs. These “non-EEM” changes will result from items such as weather, cane quality, frequency of O&M on production equipment in the mill and refinery, proper calibration of EEM equipment, changes in ancillary power use (HVAC in office space or non-mill/refinery space), changes in staffing levels, administrative/managerial decisions re: production levels, milling season, etc.

All non-EEM GHG changes can be characterized as affecting either:

- ancillary energy consumption;
- auxiliary energy consumption; or
- efficiency of production equipment and thus “main” energy consumption;
- cane quality and thus main or auxiliary energy consumption.

Ancillary energy consumption refers to energy utilized in office space or any VMC areas other than the actual mill and refinery. Auxiliary energy consumption refers to energy consumed by the mill and refinery that is not directly involved in production, milling, or refinement, but can potentially affect the performance of the EEMs. “Main” energy consumption refers to energy associated with the production/refinement equipment for which EEMs are introduced.

Figure 10 illustrates a hypothetical carbon emission profile for the first few years of the EE Project. If all parameters affecting overall carbon emissions remained stable during the project period, one would expect a somewhat cyclical annual pattern of emissions due to the declining juice/cane ratio that normally occurs during the cane growing season. Thus the projected EE case and base case might appear as depicted below. However, cane quality, weather, and other

non-EEM parameters as mentioned above introduce uncertainty into the projections. Actual profiles might appear as shown:

Figure 10. Hypothetical Projected vs. Actual Carbon Emissions.

The actual EE case, or “EE_{act}” may differ from projected because of the non EEM CO₂ changes referenced above. NOTE:

1. EE_{act} is measurable;
2. Without the M&V protocol, the “verifier” would tend to report [Base_{proj} - EE_{act}];
3. The correct reporting measure is [Base_{act} - EE_{act}];
4. Base_{act} is not directly measurable;
5. Base_{act} can be characterized as [Base_{proj} + (non EEM CO₂ changes)];
6. The protocol prescribes metering, measurement, and/or characterization of non-EEM CO₂ changes.

6.2.2 Basic M&V Protocol Outline

With consideration of the likely non EEM changes discussed above, the M&V Protocol proposed herein establishes a means for differentiating between the directly measurable energy reductions in total, and those reductions that are actually attributable to the EE measures above and beyond what the base case (“business as usual”) would yield *in actuality*.

The approach is to establish base case conditions first by documenting the existing (pre-EEM installation) production equipment, current physical conditions that could affect future energy consumption, and current operational conditions and practices that could affect future energy consumption. Next, the protocol prescribes the recording of current monthly energy consumption by facility sector (main, auxiliary, and ancillary), by fuel type, and by generation type (e.g. - utility grid, on-site diesel generator, etc.). From the energy consumption data, fuel sources, and generator efficiencies, base case GHG emission levels are established. This is simply the quantity $E_p C_p$ referenced in Equation 1.0.

The documentation of existing circumstances creates a “snapshot” of all base case conditions and allows for differentiation between future energy consumption changes that are due to the EEMs and those that are not.

Once the EEMs are installed (the EE “project case”), the protocol calls for installation of metering and submetering equipment for direct measurement of EEM and non-EEM energy consumption changes. The non EEM changes are captured by metering the appropriate physical and operational parameters for those conditions that are measurable, and establishing data collection and modeling methods for those that are not measurable but can be characterized.

Next, the post-EEM installation energy consumption is recorded and differentiated by sector, fuel type, and generating source as in the base case. But an additional step is introduced so that the true GHG reductions attributable to the EEMs may be discerned. This additional step involves projection of what the base case emissions would have been without the EE project. This quantity is defined as:

$$\text{Base}_{\text{act}} = [\text{Base}_{\text{proj}} + \text{non EEM CO}_2 \text{ changes}] \quad [6.0]$$

for the annual period, where:

$\text{Base}_{\text{proj}}$ = Projected base case GHG emission levels established before EEMs; non-EEM CO₂ changes = changes in GHG levels due to non EEM factors.

And finally, the quantity reported annually as GHG reduction due to implementation of the EE project is:

$$R_{\text{net}} = \text{Base}_{\text{act}} - E_p C_p \quad [7.0]$$

The basic outline of the M&V Protocol is presented below; the detailed steps of the protocol are given in Section 6.2.3.

- I. Base Case Conditions
- A. Document existing and proposed equipment.
 1. Production equipment;
 2. Relevant auxiliary and ancillary equipment;
 3. Current floor space devoted to production, milling, administrative functions, etc.
 - B. Document existing physical conditions.
 1. Weather and climate data (indoor/outdoor; 12 months recommended);
 2. Current cyclical data (12 months minimum) on cane quality;
 3. Relevant agricultural/agronomic conditions;
 4. Current monthly cane processing quantities.
 - C. Document existing operational conditions and practices.
 1. Current production levels;
 2. Current throughput metric (such as Steam on cane);
 3. Current milling season length;
 4. Current staffing levels;
 5. Present maintenance procedures and intervals;
 6. Present calibration procedures.
 - D. Document current energy consumption and fuel type.
 1. Differentiate consumption by main, auxiliary, and ancillary use (metering installation may be required at this baseline stage).²
 - E. Calculate base case GHG levels from “E_cC_r” in Equation 1.0.

The base case components are illustrated in Figure 11.

Figure 11. Establishing Base Case Conditions in the M&V Protocol

² The reason for designating main, auxiliary, and ancillary power consumption is primarily clarity in record-keeping, and ease in calculating energy consumption changes due to non EEM factors.

II. EE Project Case

- A. Install EEM equipment, necessary metering and submetering equipment, and document.
- B. Establish data collection, measurement, and/or modeling methods for recording physical conditions on a periodic basis; install necessary metering and submetering equipment and document;
 1. Develop algorithms for characterizing changes in main, auxiliary, and ancillary energy consumption as a result of changes in physical conditions.
- C. Establish data collection, measurement, and/or modeling methods for recording operational conditions and practices on a periodic basis; install necessary metering and submetering equipment and document;
 1. Develop algorithms for characterizing changes in main, auxiliary, and ancillary energy consumption as a result of changes in operational conditions and practices.
- D. Document post-EEM equipment installation energy consumption and fuel type annually.
 1. Differentiate consumption by main, auxiliary, and ancillary use.
- E. Determine $Base_{act}$ as $[Base_{proj} + \text{non EEM CO}_2 \text{ changes}]$ for the annual period. Non EEM CO₂ changes are defined as the product of the additional main, auxiliary, and ancillary energy consumption attributable to physical and operational conditions and practices (non EEM conditions) and the carbon intensity of that incremental energy consumption.
- F. Apply Equation 6.0 to determine true GHG reduction.

The components of the EE Project Case are illustrated in Figure 12.

Figure 12. Establishing Project Case GHG Reductions in the M&V Protocol

6.2.3 Detailed M&V Protocol Outline

The detailed steps of the protocol are presented below:

I. Base Case Conditions

A. Document Existing and Proposed Equipment (recommended in NEMVP).

1. Obtain diagrams/plans for the mill, refinery, and administrative support (office) areas. Ensure that all equipment to be retrofitted, all relevant metering and instrumentation apparatus, and equipment that will affect main, auxiliary, and ancillary energy consumption are identifiable on the diagrams.
2. Record the location and count of equipment to be retrofitted so that it can easily be located on the plans.
3. Take photographs and/or videotapes of the equipment to accurately document its condition. For each piece of equipment, or equipment lots, capture the manufacturer's model number, serial number and nameplate information.
4. Obtain an accurate count of the systems to be replaced if the retrofit involves multiple units of one type of equipment. A location diagram that indicates where new/different equipment is to be located should also accompany this.
5. For any lighting and/or HVAC retrofits considered, measure baseline lighting conditions using standard Illuminating Engineering Society (IES) measurements. For HVAC equipment, determine system setpoints and operating schedules including: thermostat setpoints; system temperature settings, i.e., cold deck temperature, boiler temperature/pressure; on/off schedules for air-handler units, pumps, air conditioners, chillers, boilers, etc.

B. Document Existing Physical Conditions.

1. Twelve months or more of monthly baseline data is required to establish base case physical conditions (NEMPV). This includes the following information: (i) daily average temperature data from a nearby airport or meteorological station (i.e., NWS min/max data), (ii) data reflecting daily average barometric pressure, humidity, precipitation, and/or other climate information that could affect milling season length or production, and (iii) indoor climate data recorded with appropriate frequency to establish any trends that could affect refinement or production.
2. Qualitative reports (again at reporting intervals appropriate to establish trends) on cane quality should also be gathered for a minimum of 12 months, as cane quality directly affects the energy consumption associated with milling and production.
3. Obtain 12 months of data reflecting relevant agricultural and/or agronomic conditions that could affect milling season length, refinement, or production.

4. Collect 12 months of data reflecting the quantities of cane processed on a monthly basis at Victorias.
- C. Document Existing Operational Conditions and Practices.
1. Many conditions, practices, procedures, and managerial decisions unrelated to the performance of the EEMs can affect energy consumption (and thus, GHG emissions) in the main, auxiliary, and ancillary sectors of the Victorias facility. As a result, it is necessary to document all such conditions in situ as part of the base case characterization. The information should include (i) current production levels, (ii) a baseline throughput metric (such as Steam on cane), (iii) the current milling season length, (iv) current staffing levels, (v) present maintenance procedures and intervals, and (vi) present instrumentation calibration procedures.
 2. The current floor plans of the facility, depicting total floor-space devoted to administrative and industrial functions should also be recorded.
- D. Document Current Energy Consumption and Fuel Type.
1. Obtain a minimum of 12 months of monthly energy consumption data from the utility (VRESCO) to establish base case (NEMPV). This includes the following information: (i) the date of the meter readings, and (ii) the amount of energy consumed during the utility billing period (i.e., the period between the current and previous month's reading).
 2. Establish either a composite resource/fuel mix assumption for Visayas grid electricity, or identify marginal NPC resources and the associated fuels that supply electricity to Victorias.
 3. Obtain a minimum of 12 months of data reflecting energy produced on-site from steam turbines and the monthly fuel consumption. Document the efficiency of the energy conversion process.
 4. Obtain a minimum of 12 months of data reflecting energy produced on-site from diesel generators and the monthly fuel consumption. Document the efficiency of the energy conversion process.
 5. Obtain a minimum of 12 months of data reflecting thermal energy produced on-site from steam generators and the monthly fuel consumption. Document the efficiency of the energy conversion process.
- E. Calculate Base Case GHG Levels.
1. Calculation of the base case GHG levels involves identification of all energy produced in the base case and the carbon intensity of the fuels consumed to produce that energy. The product of the two quantities, $E_r C_r$, as explained in Equation 1.0, is the base case emission level. The methodology is described in the steps following.
 2. Determine E_r for the total facility by combining energy consumption data for all sources. The sources include grid electricity, thermal energy consumed for process steam, and energy produced on-site by steam turbines and diesel generators. Where metered data is unavailable, the capacity of the energy converter multiplied by its hours of operation per

year (or the product of capacity, 8760 hours per year, and actual capacity factor) will yield the total energy produced by that source:

$$E_{rTOTAL} = [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source1}} + [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source2}} + \dots [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source n}} \quad [8.0]$$

3. Identify the carbon intensities of the fuels consumed from step D.2 above. As noted, it may be necessary to assume a composite fuel mix and carbon intensity for electricity supplied from the VRESCO grid unless the specific resource that supplies Victorias can be clearly delineated. Reference the U. S. Environmental Protection Agency AP-42, Supplement A, 2/96 and Supplement B, 10/96 for emission factors for various fossil fuels. The emission factors are reported in units of lbs of CO₂ per MMBtu. For electrical energy consumption, it is necessary to convert to lbs of CO₂ per kWh using the identity:

$$1 \text{ kWh} = 3413 \text{ Btu} \quad [9.0]$$

Using the heating values of the fuels themselves (reported as Btu per gallon or per unit volume -- available from standard engineering handbooks), the kWh delivered per gallon of fuel can be determined from the generator efficiency, η :

$$(\text{Btu/gal}) \times (\eta) \times (1 \text{ kWh}/3413 \text{ Btu}) = \text{kWh/gal} \quad [10.0]$$

Finally, the conversion of units becomes:

$$C_r = [(\text{Btu/gal}) \div (\text{kWh/gal})] \times [(\text{lb CO}_2/\text{MMBtu})(1 \text{ MMBtu}/10^6 \text{ Btu})] \quad [11.0]$$

Then, total annual CO₂ emissions in the base case will be derived from Equation 1.0 for each of the sources:

$$E_r C_{rTOTAL} = E_r C_{r1} + E_r C_{r2} + E_r C_{rn} \quad [12.0]$$

II. EE Project Case

A. Install EEM Equipment, Necessary Metering and Submetering Equipment, and Document.

1. Locate the installed EEM, metering, and submetering equipment on the diagrams/plans for the mill, refinery, and administrative support (office) areas that were obtained for the base case. Ensure that all retrofitted equipment, all relevant metering and instrumentation apparatus, and equipment that affect main, auxiliary, and ancillary energy consumption are identifiable on the diagrams. Verify that actual installation matches proposed and/or note any relevant "as built" changes.
2. Take photographs and/or videotapes of the EEM, metering, and submetering equipment to accurately document its condition. For each piece of equipment, or equipment lots, capture the manufacturer's model number, serial number and nameplate information.
3. Develop metering and monitoring reporting protocols. Metering and monitoring reports must address exactly what was measured, how, with what meter, when, and by whom. Calibration of sensors and meters to known standards is required to ensure that data collected is valid. Project information and metered data must be maintained in usable formats. Both "raw" and "compiled" data should be submitted to the owner with the post-installation and regular interval reports.

The duration of metering and monitoring must be sufficient to ensure an accurate representation of the average amount of energy used by the affected equipment both before and after project installation. The measurements should be taken at typical system outputs within a specified time period, such as one month. These measurements can then be extrapolated to determine annual and time-of-use period energy consumption. The required length of the metering period depends on the type of project.

B. Establish Data Collection, Measurement, and/or Modeling Methods for Recording Physical Conditions on a Periodic Basis; Install Necessary Metering and Submetering Equipment and Document.

1. Physical conditions at Victorias may introduce uncertainty into the changes in energy consumption and thus, GHG emission levels. As noted in part I.B of Section 7.2.3 (page 48), such physical conditions may include, but are not limited to (i) weather and indoor/outdoor climate, (ii) cane quality, (iii) agricultural/agronomic conditions, and (iv) cane processing quantities. For those variable physical conditions for which data can be reported directly, establish data collection procedures.
2. For those variable physical conditions that cannot be measured or for which data are not available, develop algorithms and/or modeling

- procedures for characterizing changes in main, auxiliary, and ancillary energy consumption as a result of changes in physical conditions.
3. For those variable physical conditions that are measurable, install necessary metering and submetering equipment and document its installation as in parts II.A.1 - II.A.3 of this outline.
- C. Establish Data Collection, Measurement, and/or Modeling Methods for Recording Operational Conditions on a Periodic Basis; Install Necessary Metering and Submetering Equipment and Document.
1. As noted in Section 7.2.1, changes in operational conditions and practices may also introduce uncertainty into the changes in GHG levels that are attributable to EEMs. Such conditions and practices may include production levels, milling season length, staffing levels, maintenance procedures and intervals, calibration procedures, and floor space devoted to administrative and industrial operations. As in Part II.B of this outline, for those variable operational conditions and practices for which data can be reported directly, establish data collection procedures.
 2. For those variable operational conditions and practices that cannot be measured or for which data are not available, develop algorithms and/or modeling procedures for characterizing changes in main, auxiliary, and ancillary energy consumption as a result of changes in operational conditions.
 3. For those variable operational conditions and practices that are measurable, install necessary metering and submetering equipment and document its installation as in parts II.A.1 - II.A.3 of this outline. This may be relevant in the case of establishing a throughput metric, such as steam on cane.
- D. Document Post-EEM Equipment Installation Energy Consumption and Fuel Type Annually.
1. Although reporting of energy consumption and net GHG reductions will take place annually, it is necessary to track energy data on a monthly basis as prescribed in the base case portion of this protocol. Obtain monthly energy consumption data from the utility (VRESKO) for a period of one year after installation of the EEMs and metering equipment. This includes the following information: (i) the date of the meter readings, and (ii) the amount of energy consumed during the utility billing period (i.e., the period between the current and previous month's reading).
 2. Verify the composite resource/fuel mix assumption for VRESKO grid electricity that was used in the base case, or identify marginal NPC resources and the associated fuels that supply electricity to Victorias. If the identified resource and associated fuel vary from the base case assumption, note the relevant changes. Such changes will have to be addressed in the GHG calculations.

3. Collect data reflecting energy produced on-site from steam turbines and the monthly fuel consumption for a period of one year after installation of the EEMs and metering equipment. Document the efficiency of the energy conversion processes. If efficiency has changed since the base case was established, the change must be noted here and reconciled with characterization of the operational and/or physical changes that caused the change in efficiency.
 4. Collect data reflecting energy produced on-site from diesel generators and the monthly fuel consumption for a period of one year after installation of the EEMs and metering equipment. Document the efficiency of the energy conversion process. Again, if efficiency has changed since the base case was established, the change must be noted here and reconciled with characterization of the operational and/or physical changes that caused the change in efficiency.
 5. Collect data reflecting thermal energy produced on-site from steam generators and the monthly fuel consumption. Document the efficiency of the energy conversion process. Again, if efficiency has changed since the base case was established, the change must be noted here and reconciled with characterization of the operational and/or physical changes that caused the change in efficiency.
- E. Determine Base_{act} as $[\text{Base}_{\text{proj}} + \text{non EEM CO}_2 \text{ Changes}]$ for the Annual Period.
1. Calculation of the actual (vs. projected) base case GHG levels must be done to get a true indication of what the base case GHG levels would be if implementation of the EE Project had not taken place. As noted in Section 7.2.1, variable physical and operational parameters are likely to change actual emission levels in the non-project case.
 2. Refer to Equation 5.0 on page 47. From this equations, determine the total GHG emission level changes due to non-EEM factors. These non EEM CO_2 changes will be determined from a combination of meter and submeter data, data collection, and characterization of the variable physical and operational parameters that have been discussed thus far. Calculation of total non-EEM CO_2 changes involves implementation of those metering, measurement, and modeling protocols established in parts II.B and II.C of this protocol.
 3. Apply Equation 6.0 to determine Base_{act} .
- F. Apply Equation 6.0 to Determine True GHG Reduction.
1. As in the base case projection methodology, determination of actual EE project emission levels involves identification of all energy produced in the project case and the carbon intensity of the fuels consumed to produce that energy. The product of the two quantities, $E_p C_p$ as explained in Equation 1.0, is the project case emission level. The methodology, which mirrors the base case procedure, is described in the steps following.
 2. Determine E_p for the total facility by combining energy consumption data for all sources. The sources include grid electricity, thermal energy consumed for process steam, and energy produced on-site by steam turbines and diesel generators. Where metered data is unavailable, the

capacity of the energy converter multiplied by its hours of operation per year (or the product of capacity, 8760 hours per year, and actual capacity factor) will yield the total energy produced by that source:

$$E_{pTOTAL} = [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source1}} + [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source2}} + \dots [(kW)(8760h/yr) \times (\text{capacity factor})]_{\text{source n}} \quad [13.0]$$

3. Identify the carbon intensities of the fuels consumed from step D.2 above. As noted, it may be necessary to assume a composite fuel mix and carbon intensity for electricity supplied from the VRESCO grid unless the specific resource that supplies Victorias can be clearly delineated. Reference the U. S. Environmental Protection Agency AP-42, Supplement A, 2/96 and Supplement B, 10/96 for emission factors for various fossil fuels. The emission factors are reported in units of lbs of CO₂ per MMBtu. For electrical energy consumption, it is necessary to convert to lbs of CO₂ per kWh using Equation 9.0.

Using the heating values of the fuels themselves (reported as Btu per gallon or per unit volume -- available from standard engineering handbooks), the kWh delivered per gallon of fuel can be determined from the generator efficiency, η , as in Equation 10.0.

Complete the conversion of units as in Equation 11.0.

Then, total annual CO₂ emissions in the project case will be derived from Equation 1.0 for each of the sources:

$$E_p C_{pTOTAL} = E_p C_{p1} + E_p C_{p2} + E_p C_{pn}. \quad [14.0]$$

The final step in determining the true GHG reduction attributable to the EE Project is to apply Equation 7.0, which yields the difference between Base_{act} and E_pC_p.

6.3 References

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"Proceedings of the United States Initiative on Joint Implementation Program Conference", Arlington, VA; May 31-June 1, 1995.

6.4 Phase 2: Cogeneration Project

6.4.1 Monitoring & Verification for Phase 2

M&V for the Phase 2 project is much more straightforward than the protocol proposed for Phase 1. The complexity of Phase 1 M&V is due in large part to the uncertainties associated with events not related to the EEM's implemented. Further, discerning which deviations (from initial base case and project case emission projections) are due to EEM and non-EEM factors requires data collection, measurement, and/or characterization.

For Phase 2, the annual emission offsets that must be monitored and verified are simply those emissions associated with VMC's eliminated electricity purchases and power exports. While uncertainties do exist about the actual dispatching of plants in future years or the possibility of changes in capacity factors or carbon intensities of particular marginal resources, documentation systems are already in place to capture those changes. Thus, annual monitoring and verification for Phase 2 will simply be a matter of monitoring VMC's electricity sales to the grid, and performing an annual assessment of those factors which become dependent variables in the carbon cycle calculations presented herein. Those factors -- plant heat rates, capacity factors, carbon intensities, etc. may indeed change during the project period and will affect the final calculations resulting from Equation 5.0 (page 45).

Thus, M&V for Phase 2 is simply:

1. Calculate the net projected offset from Equation 5.0 in year 1.
2. Annually monitor VMC's actual electricity sales to the Visayas grid.
3. Annually revisit the NPC Resource Plan and empirical generation data to discern any changes in heat rates, marginal plants, carbon intensities, or other factors that would affect carbon cycle calculations.

If no changes occur, the reported emission offset for that year can be calculated from Equation 5.0 for that year's energy sales. If changes do occur, they must be factored into Equation 5.0 and calculations performed for that year's energy sales to the Visayas grid.

7 NGOs

EIC has not yet established a formal relationship with a suitable NGO for third-party monitoring of the project. However, informal discussion have taken place with Preferred Energy Investments, a non-profit organization based in Manila. PEI's mission is to promote the financing of renewable energy projects in the Philippines, and it has several NGOs with which it works which may become viable partners in the Victorias project.

8 Host Country Acceptance

Discussions with the Department of Environment and Natural Resources (DENR) have taken place on three occasions in Manila, Philippines regarding the Victorias project. The DENR is the lead agency for granting host country acceptance. In October 1997, Rick Renner and Michael Ashford from EIC met with Antonio G. M. La Viña, then Undersecretary for Legal and Legislative Affairs. Also attending the meeting was Cecilia G. Dalupan-San Andres, a lawyer in the Mr. La Viña's department.

In this meeting, EIC briefed the undersecretary on the project and we discussed several of the relevant issues regarding host country acceptance. In principle, the DENR was in favor of the project and encouraged EIC to move forward with it. In the meeting we also discussed the monitoring and verification aspects of the project. EIC expressed its interest in working with an NGO to be a long-term contractor for M&V activities, and Undersecretary La Viña suggested that working with a local, i.e., Negros-based NGO would be the most effective solution, as they would be better attuned to the local stakeholders' concerns.

In February, 1998 on a return trip to continue work on the Victorias project, Rick Renner spoke with Flordeliz Andres of Undersecretary La Viña's office by phone. Progress on the project was discussed.

In April 1998, in a follow-on trip by Rick Renner, he met with Ms. Andres to discuss next steps for gaining host country acceptance. Ms. Andres suggested that EIC and Victorias submit a formal letter to the DENR before the June presidential elections in order to stake a claim for the project, in essence. The letter would be a placeholder intended to allow the DENR to prepare its own list of projects intended for JI certification.

Unfortunately, Victorias was not able to sign such a letter given its uncertain financial condition and the lack of clear authority among the management. During this period, EIC was having significant trouble getting necessary attention to continue technical analyses at the factory for energy efficiency and cogeneration design requirements. The JI certification process was considered a distraction by Victorias management and EIC decided not to push the issue too far.

Because of the uncertain economics of the project, along with the remaining stasis at Victorias, EIC has not pursued gaining host country acceptance since May. Upon resumption of project development (given certain changes in project economics and management), EIC will pursue the certification as a Clean Development Mechanism project based on the Kyoto protocol of 1997.

9 Data Collection

EIC has used various sources for data in this analysis. All of the information on Victorias' energy consumption and generation has come from data recorded over several years at the factory level. These data were retrieved over a period of several months from plant operating personnel. These data were used for baseline analysis. Project case data were generated by EIC from its cogeneration project design study.

Data for load and capacity projections in the regional grids were collected from the National Power Corporation's Power Demand Forecast and Expansion Plan (1995). This document was obtained from NPC directly.

Generation data as shown in Table 5 were obtained from NPC's regional office in Cebu City, Cebu (Visayas). EIC was assisted in the collection of this data by Preferred Energy Incorporated, a Manila-based consulting and analysis firm.

PHILIPPINES