Koina Kondre Area Project
Pre-feasibility Study

Report to the Inter-American Development Bank

28 June 2019

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1 Introduction

N.V. Energie Bedrijven Suriname (EBS) is the state-owned utility responsible for generating, transmitting, and distributing electricity in Suriname. EBS serves close to 160,000 customers in urban coastal areas as well as rural villages in the interior of the country. The utility has a total installed capacity of approximately 213MW.[1] Thermal-based generation represents 100 percent of the utility's installed capacity. EBS generates roughly 444,100MWh annually—about 29 percent of the electricity used in Suriname each year.

EBS owns and operates Energievoorziening Paramaribo (EPAR)—the largest electricity system in the country.[2] EPAR provides electricity to approximately 90 percent of EBS' customer base. The system serves 143,485 customers in Paramaribo, the capital, and the surrounding areas of Wanica, Saramacca, Commewijne, and Para.

The EPAR system has four power plants with a total installed capacity of 455MW. EBS owns two plants that total about 170MW of EPAR's installed capacity—Saramaccastraat DPP1 (83MW) and Saramaccastraat DPP2 (86MW). Independent power producers own the plants that provide the remaining installed capacity—the SPCS Power Plant (96MW) and the Afobaka Hydro Power Facility (189MW). The SPCS Plant is owned and operated by a subsidiary of Staatsolie, the state-owned oil company. The Afobaka Hydro Power Facility is currently owned and operated by Suralco, a private aluminum company. This facility will become state-owned on 1 January 2020.[3]

In 2017, peak demand in the EPAR system was 203MW and customers consumed approximately 1,420GWh of electricity. According to Suriname's Electricity Sector Plan (ESP), electricity demand in EPAR is expected to grow an average 4.3 percent annually for the next 5 years. This estimate is in line with EPAR's service coverage projections and the country's estimated economic growth.

EPAR customers receive service comparable to that of other utilities in the region. In 2016, EPAR's System Average Interruption Frequency Index (SAIFI) was 6 outages per year. This was relatively low compared to the regional average, although the outages experienced by EPAR customers were relatively long. That same year, the System Average Interruption Duration Index (SAIDI) for EPAR was 767 minutes per year—roughly 13 hours.

There are approximately 132 rural villages across Suriname that are not connected to EPAR or any grid within the National Power System. Instead, most villages receive electricity at no cost from small diesel generators, which are owned and operated by the Ministry of Natural Resources.[4] These generators typically provide up to 6 hours of electricity per day to

[1] Installed capacity was estimated using data from 2017 for three power plants (Saramaccastraat DPP1, Saramaccastraat DPP2, and Clara Power Plant), as well as for generators in rural areas.

[2] EBS controls the National Power System in its entirety, which is made up of various isolated electricity systems.

[3] Suralco built the Afobaka Hydro Power Plant after signing the Brokopondo Agreement with the State in 1958. Through the agreement, Suralco also built an aluminum smelter, an alumina refinery, and other facilities, and entered into a long-term arrangement to sell the electricity it did not use from Afobaka to EBS. The Brokopondo Agreement will end on 31 December 2019, upon which Suralco will transfer Afobaka along with associated assets to the Government.

[4] The Rural Electrification Department within the Ministry of Natural Resources is the agency in charge of overseeing the electricity provision to the villages. In all, the generators have an aggregate installed capacity of 7MW.

households.[5] In villages south of Powakka, located south of Paramaribo, most households receive electricity for 4 to 5 hours a day. Other households do not receive any electricity at all.

With the support of the Inter-American Development, EBS is considering investing in a 12kV distribution system to connect several villages in Koina Kondre, an area south of Powakka. This system would expand from the substation in Powakka to the southern village of Marshall Creek. It would allow EBS to expand coverage and provide customers with continuous 24-hour service from EPAR.

This report presents detailed information about the project, including:

- A detailed description of the project, including its justification, preliminary design, estimated costs, and proposed implementation timeline (Section 2)
- The expected benefits for the project associated with improving operations and installing new connections (Section 3)
- The proposed budget for developing the project. This includes the estimated capital expenditures for the engineering, procurement, and construction of the project, as well as the estimated operating expenditures (Section 4)
- The economic costs and benefits of developing the project, given the reduction in energy-not-served for EBS and the incremental energy supplied to new connections (Section 5).
- The main conclusions and recommendations for project development, based on the information presented in previous sections (Section 6).

[5] The generators are owned and operated by the Rural Electrification Department of the Ministry of Natural Resources (DEV), which provides the service to customers at no charge

2 Project Description

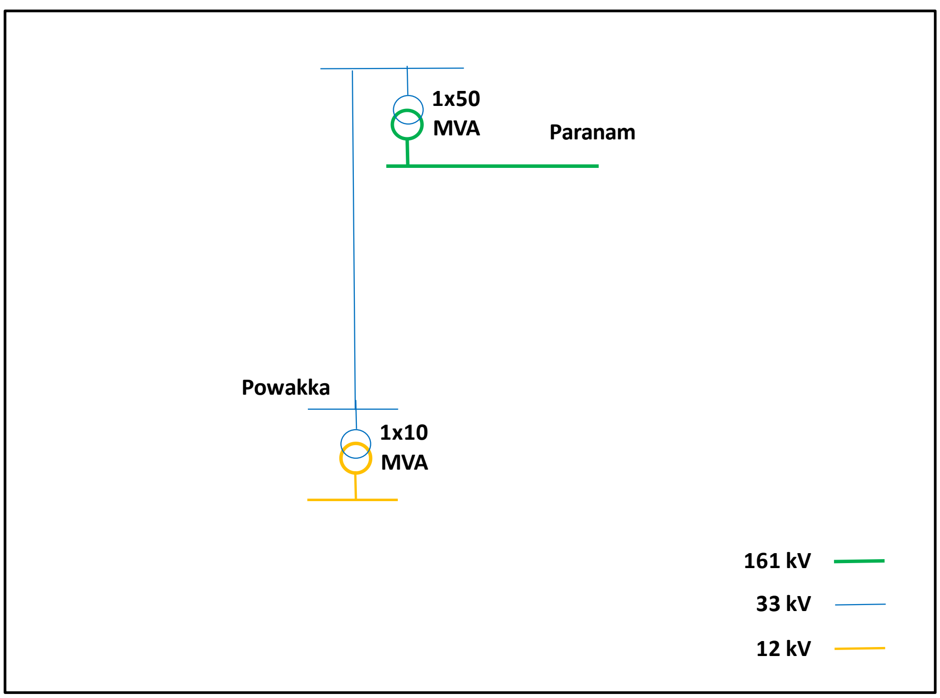
EBS is considering building a 12kV distribution system in Koina Kondre, a rural area to the south of Powakka. The proposed distribution system is meant to provide service coverage to villages in the Koina Kondre area. Currently, these villages are not connected to the National Power System and have limited access to electricity. The new distribution system would address this challenge by connecting these villages to the EPAR system, thereby ensuring continuous service to the area (Section 2.1).

This study considers a preliminary design that includes a 12kV line as well as medium and low-voltage equipment to connect new customers to the distribution system. These works cost an estimated US$1.8 million in present value terms (Section 2.2). The project would take approximately 3 years to develop. It would be ready to be commissioned on 1 January 2023 (Section 2.3).

2.1 Project Justification

Currently, there is no transmission or distribution system that extends to the south of Powakka. This area, which stretches 24km from Powakka to the village of Marshall Creek, is known as Koinda Kondre. The closest substation to Koina Kondre is the Powakka substation, which receives its electricity supply at 33kV from the Paranam substation in the north. The Powakka substation is also equipped with a 10 MVA transformer at 33/12kV. Figure 2.1 shows the current configuration of the substation and associated line near the area of influence of the new project.

Figure 2.1: Electrical Subsystem in Area of Influence—Current Configuration



In Koina Kondre, villages are not connected to the National Power System. Instead, electricity is provided by small diesel generators that are owned and operated by the Ministry of Natural

Resources. Although the service provided is free, most households only receive 4 to 5 hours of electricity a day. Other households do not receive any electricity at all.

There is broad consensus that access to modern electricity services is necessary to support human development, reduce poverty, and promote economic growth.[6] In Koina Kondre, the limited access to electricity can negatively impact the quality of life of citizens. Households, for example, are unable to use modern appliances or access the internet. Households may resort to cooking with open fires or stoves that rely on solid fuels or kerosene, which can result in illnesses caused by high levels of indoor air pollution. Industries and commerce are also strained by lack of access to electricity—production and activities are restricted, resulting in a loss of output. Business that rely on self-generation for continuous service are also burdened by the associated costs.

The proposed distribution system is meant to ensure continuous, modern, electricity services to villages in Koina Kondre. Initially, close to 600 households, along with two recreational centers, and five wood concessionaires would directly benefit from the project. Once access to the EPAR system is in place, housing developments, businesses, and industries are expected to grow in number. EBS would also be able to use the new distribution system to accommodate any new demand in the area.

2.2 Preliminary Design and Costing

The preliminary design for the distribution system at Koina Kondre includes a 12kV line and the medium and low-voltage equipment that is needed to connect new customers. The 12kV line would have a single-circuit configuration and extend approximately 24km. The line would start from the south side of the Powakka substation and run along Afobaka Road to the village of Marshall Creek, providing electricity to several villages along this route. Figure 2.2 shows an aerial map with the preliminary route of 12kV line in red. The map also shows the location of the main villages located nearby.

[6] The World Bank. 2017. "Overview: State of Electricity Access Report." Accessed 14 June 2019. http://documents.worldbank.org/curated/en/285651494340762694/pdf/114841-ESM-PUBLIC-P148200-32p-FINALSEAROverviewWEB.pdf

Figure 2.2: Proposed Route of the Project

Source: Google Earth.

Given the proposed length of the route and the line specifications, it is estimated that 261 medium-voltage poles would be needed for the project. This design includes galvanized steel or concrete poles with an average height of 12 meters and a span of 60 meters. Additionally, the design considers one SAX-W 70 conductor per phase.[7] The SAX-W 70 is an aluminum conductor made of AAAC alloy with a 56.3 mm diameter and XLPE insulation. Given the installation conditions in Suriname, the ampacity of this cable is 373 A (see calculations in Appendix B). Table 2.1 provides an overview of the poles required to build the project based on these specifications.

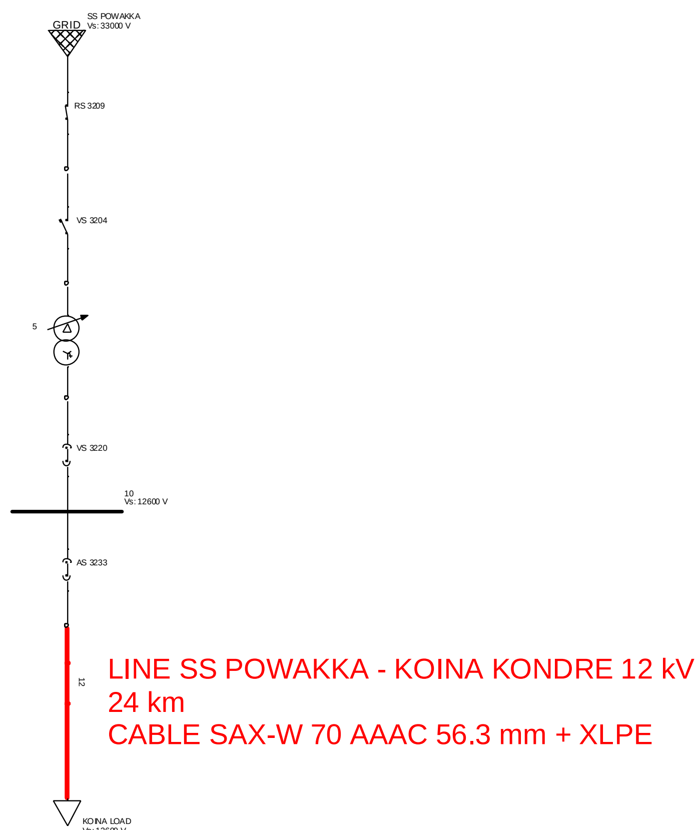
[7] This conductor was selected based on EBS' recommendation for medium-voltage conductors for 12kV feeders in areas with high vegetation density.

Table 2.1: Pole Structure Specifications and Quantity

Item No.	Structure Specifications	Quantity
1	Tangent pole	325
2	Small angle pole	10
3	Section pole	46
4	5 – 30° pole	1
5	30 – 60° pole	1
6	60 – 90° pole	1
	Total	**384**

The proposed project does not require any construction at the substation level to connect the 12kV line. The Powakka substation currently has two spare 12kV breakers available, one of which could be used to connect the 12kV line. Figure 2.3 shows a single-line diagram of the project. The connection to the breaker AS 3233 at the Powakka substation is highlighted in red.

Figure 2.3: Implementation Scheme



Medium and low-voltage equipment would be needed to connect the villages along the route of the 12kV line. Based on the demand forecasted for Koina Kondre, approximately 598 households, two recreational centers, and five wood concessionaires would initially receive service from the proposed distribution system. The preliminary design of the project would thereby include transformers, conductors, cables, smart meters, and low-voltage poles for residential, commercial, and industrial customers.

Under this design, approximately twenty 3x25kVA transformers with a 12kV/120-208V ratio would be needed to connect residential customers. Each transformer would provide electricity to a group of approximately 40 houses. The design also considers a low-voltage network that is 400 meters in length, along with an AAAC 1/0 AWG conductor for each transformer. Additionally, the design includes a smart meter for every house, along with a THW CU #8 tripolar cable that is approximately 40 meters long, and low-voltage poles.

For commercial and industrial customers, the design considers ten 3x100kVA transformers with a 12kV/120-208V ratio. The design also includes smart meters for these customers, along with a THW CU 4/0 AWG tripolar cable that is 40 meters long and low-voltage poles. Table 2.2 presents an overview of the medium and low-voltage equipment needed to connect all actual customers in the Koina Kondre area, and a reserve margin of 33 percent for future incorporations.

Table 2.2: Medium- and Low-Voltage Equipment and Specifications

Item No.	Structure Specifications	Quantity
1	Transformer 3x25kVA 12kV/120-208V	20 units
2	Transformer 3x100kVA 12kV/120-208V	10 units
3	Low-voltage network conductor AAAC 1/0 AWG (3 Phases + 1 Neutral)	12,000 meters
4	Tripolar cable THW CU #8	32,000 meters
5	Tripolar cable THW CU 4/0 AWG	380 meters
6	Low-voltage poles 25 ft	425 units
7	Smart meters	805 units

Capital expenditures (CAPEX) for the project are estimated at US$1.8 million in present value terms (or approximately US$2.1 million in current dollars). Table 2.3 provides the breakdown of CAPEX required. The table includes the unit costs for the 12kV transmission line and the medium and low-voltage system, which is comprised of the equipment listed above. Each unit cost includes engineering, procurement, and construction (EPC) costs, as well as labor costs. The table also includes overhead (OH) costs for each line item, which were estimated as 10 percent of the unit costs. This CAPEX was used to estimate the total budget for the project (see Section 4 for more information on the budget estimate).

Table 2.3: Capital Expenditures (CAPEX) Required

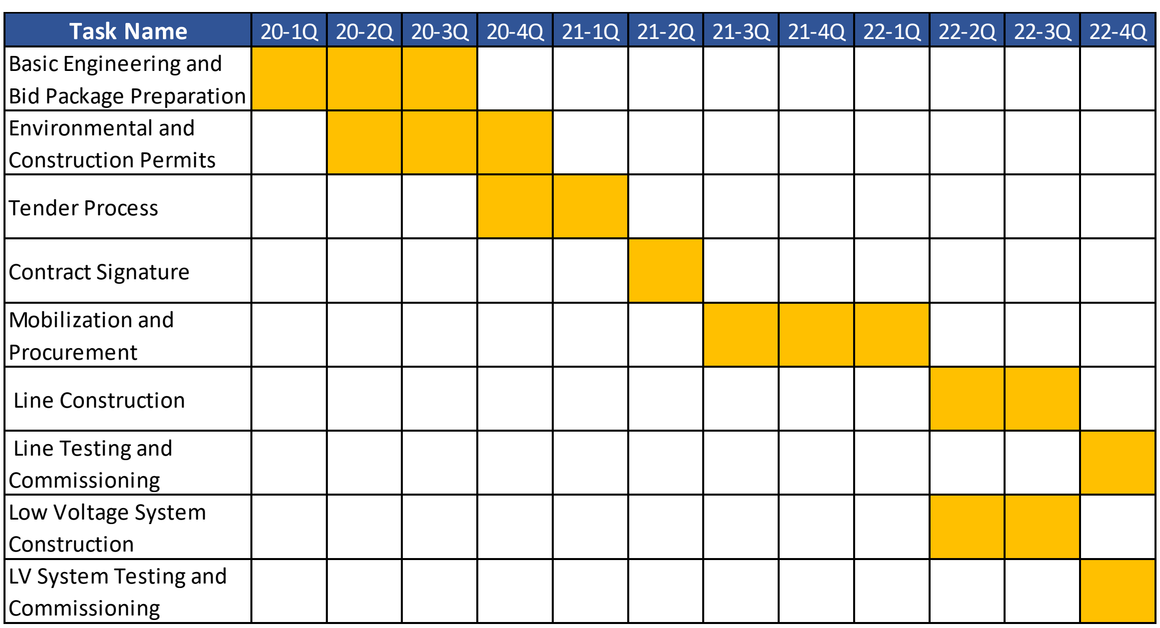
Item	Quantity	Unit Cost (US$)	OH Costs (US$)	Total Unit Cost (US$)	Total OH (US$)	Total Cost (US$)
Transmission line 12kV (overhead single circuit)—Powakka to Marshall Creek	24 km	65,000/km	6,500/km	1,560,000	156,000	1,716,000
Medium and low-voltage system	805 connections	425.5/ connection	42.6/ connection	342,527	34,253	376,780
			Total	**1,902,528**	**190,253**	**2,092,780**
					Total NPV (US$)*	**1,786,332**

Note: CAPEX provided are based on international average values, adapted to local conditions in Suriname. These values cover EPC costs and include labor. (*) The NPV was calculated assuming a discount rate of 10 percent, which was approved by the Government of Suriname for the Electricity Sector Plan.

2.3 Project Implementation

Based on the project requirements, it is estimated that the proposed distribution system could be developed in about 3 years. The activities would begin in January 2020 and end in December 2023, so the project could be commercially commissioned on 1 January 2023. Figure 2.4 shows the proposed implementation schedule.

Figure 2.4: Implementation Schedule for the Project



A brief description of each activity in the implementation schedule is provided below:

- **Basic Engineering and Bid Package Preparation**—Basic Engineering and Bid Package Preparation includes developing the basic engineering of the project, as well as developing the appropriate Terms of Reference for the contracting process
- **Environmental and Construction Permits**—Environmental and Construction Permits includes carrying out the Environmental Impact Studies required by Surinamese law and acquiring the relevant permits
- **Tender Process**—The Tender Process refers to the public process required to select the contractors in charge of completing the works, according to the requirements set by the IDB
- **Contract Signature**—Contract Signature refers to the process of discussing contract terms between the parties, preparing the required guarantees for the contractors, and signing the required contracts
- **Mobilization and Procurement**—Mobilization and Procurement includes the process through which contractors procure the goods and services required. It also includes the mobilization to the work site to develop necessary temporary infrastructure
- **Line Construction**—Line Construction refers to the process of evaluating the proposed line route, erecting the structures, installing the fittings and insulators, and laying the conductors
- **Line Testing and Commissioning**—Line Testing and Commissioning includes performing all line testing and commissioning activities, as well as identifying and correcting issues to accept the work and start the commercial operation
- **Low-Voltage System Construction**—Low-Voltage System Construction refers to the installation of the distribution transformers, conductors, smart meters, cables, and low-voltage poles.
- **Low-Voltage System Testing and Commissioning**—Low-Voltage System Testing and Commissioning includes performing all testing and commissioning activities, as well as identifying and correcting issues to accept the work and start commercial operation.

3 Expected Benefits and Impacts

The expected benefits of this project were estimated at US$2.7 million in present value terms.[8] These benefits were calculated using two metrics that can be directly attributed to the project—the reduction in generation costs and the increase in the electricity supplied to new customers.

The reduction in generation costs measures the benefits associated with limiting the use of the small diesel generators operated by the Ministry of Natural Resources (Section 3.1). The increase in the electricity supplied refers to the total demand that would be supplied by EBS in the area. Customers that previously relied on these generators (or self-generation) would instead be billed for receiving service from EBS. The incremental energy provided by EBS is associated with an increase in operating revenue for the utility. This benefit can be monetized assuming an average distribution tariff of US$37.5 per MWh (Section 3.2).

3.1 Reduction in Generation Costs

The proposed distribution system in the Koina Kondre area would result in the reduction of generation costs for all evaluated years. By connecting customers directly to the EPAR system, the Ministry of Natural Resources would no longer need to operate the small diesel generators used in the area. The demand currently served with these generators has a peak of 188 kW, value of generation capacity that will be assumed to evaluate the generation reduction benefit. The energy produced by these generators has been estimated in 263 MWh each year, which would result in savings.

The reduction in generation cost were monetized based on installed capacity (in kW) and electricity generation (in MWh). The reduction in installed capacity was monetized assuming US$170 per kW-year, and the reduction in electricity generated was monetized assuming US$214.1 per MWh (see Appendix A.2 for more information on these costs).

Overall, the reduction in generation costs represents savings of approximately US$621,054 in net present value over the 2023-2042 period. The reduction in installed capacity accounts for approximately US$224,871 of total savings in net present value, while the reduction in electricity generated accounts for US$396,183. Table 3.1 shows the values associated with the reduction in generation costs over 20 years.

Table 3.1: Total Benefits Provided by Reduction in Generation Costs (2023-2042)

Year	Installed Capacity (kW)	Electricity Generated (MWh)	Value of Installed Capacity (US$)	Value of Electricity Generated (US$)	Total Value (US$)
2023	188	263	31,960	56,308	88,268
2024	188	263	31,960	56,308	88,268
2025	188	263	31,960	56,308	88,268
2026	188	263	31,960	56,308	88,268
2027	188	263	31,960	56,308	88,268

[8] The net present value of these benefits was calculated assuming a discount rate of 10 percent. This discount rate was approved by the Government of Suriname for the Electricity Sector Plan. To see the economic viability of the project with a 12 percent discount rate, see the sensitivity analysis in Section 5.

Year	Installed Capacity (kW)	Electricity Generated (MWh)	Value of Installed Capacity (US$)	Value of Electricity Generated (US$)	Total Value (US$)
2028	188	263	31,960	56,308	88,268
2029	188	263	31,960	56,308	88,268
2030	188	263	31,960	56,308	88,268
2031	188	263	31,960	56,308	88,268
2032	188	263	31,960	56,308	88,268
2033	188	263	31,960	56,308	88,268
2034	188	263	31,960	56,308	88,268
2035	188	263	31,960	56,308	88,268
2036	188	263	31,960	56,308	88,268
2037	188	263	31,960	56,308	88,268
2038	188	263	31,960	56,308	88,268
2039	188	263	31,960	56,308	88,268
2040	188	263	31,960	56,308	88,268
2041	188	263	31,960	56,308	88,268
2042	188	263	31,960	56,308	88,268
		Total (US$)	**639,200**	**1,126,160**	**1,765,360**
		Total NPV (US$)*	**224,871**	**396,183**	**621,054**

Note: Please see Appendix A.2 for more information on how we calculated the values of installed capacity and electricity generated.

(*) Note: Net present values were calculated assuming a 10 percent discount rate.

3.2 Increase in Electricity Supplied

The proposed distribution system would result in the increase of electricity supplied from the EPAR system. Customers in Koina Kondre would be charged for the electricity service received, which would result in an increase in operational revenue for EBS. The increase in incremental energy provided to customers was monetized assuming an average distribution tariff of US$37.5 per MWh. This value corresponds to the part of the distribution and marketing rate that should be applied in economic conditions, according to the average rates in the region (see Appendix A.3 for more information on this tariff).

Overall, the increase in demand for electricity provided by EBS represents benefits of approximately US$2 million in net present value over the lifetime of the project. Table 3.1 shows the estimated demand from commercial and industrial customers, along with associated benefits, from 2023 to 2042. For more information on the estimated demand during this period, see Appendix A.1.

Table 3.2: Total Benefits Associated with Increase in Electricity Supplied (2023-2042)

Year	Electricity (MWh)	Value of Electricity Provided (US$)
2023	5,576	209,090
2024	5,855	219,545
2025	6,147	230,522
2026	6,455	242,048
2027	6,777	254,151
2028	7,116	266,858
2029	7,472	280,201
2030	7,846	294,211
2031	8,238	308,922
2032	8,650	324,368
2033	9,082	340,586
2034	9,355	350,804
2035	9,635	361,328
2036	9,924	372,168
2037	10,222	383,333
2038	10,529	394,833
2039	10,845	406,677
2040	11,170	418,878
2041	11,505	431,444
2042	11,850	444,387
	Total (US$)	**6,534,351**
	Total NPV (US$)*	**2,032,645**

(*) Note: Net present values were calculated assuming a 10 percent discount rate.

4 Budget Estimate

The proposed budget for the project was estimated at approximately US$2.1 million in net present value.[9] The budget includes the following costs:

- **Capital expenditures (CAPEX)**—CAPEX includes labor and materials associated with the engineering, procurement, and construction (EPC) of the project. This also includes overhead costs, which are equal to 10 percent of labor and materials (see Section 2.2 for more information on CAPEX). CAPEX excludes the return on the investment—that is, it excludes the cost incurred by the Government of Suriname to service the debt for this project and any other financial expenses[10]
- **Operation expenditures (OPEX)**—OPEX includes fixed and variable costs associated with properly operating and maintaining the project. Annual OPEX is assumed at 2 percent of total CAPEX.

The table below shows the budget estimates during the lifetime of the project.

Table 4.1: Budget Estimate (2020-2042), in Net Present Value (US$)

Cost	Total NPV (US$)
CAPEX	**1,786,332**
Labor and Materials	1,623,938
Overhead	162,394
OPEX	**294,496**
Total	**2,080,828**

[9] Assuming a 10 percent discount rate.

[10] See Appendix C for more information on the financial cash flows for the project.

5 Economic Analysis

The proposed distribution system can provide economic benefits to EBS and to citizens in the Koina Kondre area. The project would have a net present value of US$572,871 and an internal rate of return of 13.7 percent. The project would accrue revenue over the course of its lifetime. As a result, the project's benefits would be close to 28 percent larger than its estimated costs.[11]

The project would start yielding economic benefits in 2023—year 4 of the project. Table 5.1 shows the economic cash flow for the benefits, including the net present value. This evaluation used the present value for cash flows in 2020 and discounted the cash flows in subsequent years using a 10 percent discount rate.

Table 5.1: Economic Cash Flows—Total Benefits (2020-2042)

	unit	2020	2021	2022	2023	2024
Reduction in Generation Costs						
Fixed costs	US$/year	-	-	-	31,960	31,960
Variable costs	US$/year	-	-	-	56,308	56,308
Total, costs avoided due to reduction in generation	**US$**	**-**	**-**	**-**	**88,268**	**88,268**
Increase in Electricity Supplied						
Price per MWh	US$/MWh					
Added incremental demand	kW				5,576	5,855
Total, revenues due to incremental demand	**US$**	**-**	**-**	**-**	**209,090**	**219,545**
Total, Benefits	**US$**	**-**	**-**	**-**	**297,358**	**307,813**

	unit	2025	2026	2027	2028	2029
Reduction in Generation Costs						
Fixed costs	US$/year	31,960	31,960	31,960	31,960	31,960
Variable costs	US$/year	56,308	56,308	56,308	56,308	56,308
Total, costs avoided due to reduction in generation	**US$**	**88,268**	**88,268**	**88,268**	**88,268**	**88,268**
Increase in Electricity Supplied						
Price per MWh	US$/MWh					
Added incremental demand	kW	6,147	6,455	6,777	7,116	7,472
Total, revenues due to incremental demand	**US$**	**230,522**	**242,048**	**254,151**	**266,858**	**280,201**
Total, Benefits	**US$**	**318,790**	**330,316**	**342,419**	**355,126**	**368,469**

	unit	2030	2031	2032	2033	2034
Reduction in Generation Costs						
Fixed costs	US$/year	31,960	31,960	31,960	31,960	31,960
Variable costs	US$/year	56,308	56,308	56,308	56,308	56,308
Total, costs avoided due to reduction in generation	**US$**	**88,268**	**88,268**	**88,268**	**88,268**	**88,268**
Increase in Electricity Supplied						
Price per MWh	US$/MWh					
Added incremental demand	kW	7,846	8,238	8,650	9,082	9,355
Total, revenues due to incremental demand	**US$**	**294,211**	**308,922**	**324,368**	**340,586**	**350,804**
Total, Benefits	**US$**	**382,479**	**397,190**	**412,636**	**428,854**	**439,072**

[11] The estimated costs do not include cost for debt service or other financial expenses. See Appendix CAppendix C for more information on the financial cash flows for the project.

	unit	2035	2036	2037	2038	2039
Reduction in Generation Costs						
Fixed costs	US$/year	31,960	31,960	31,960	31,960	31,960
Variable costs	US$/year	56,308	56,308	56,308	56,308	56,308
Total, costs avoided due to reduction in generation	**US$**	**88,268**	**88,268**	**88,268**	**88,268**	**88,268**
Increase in Electricity Supplied						
Price per MWh	US$/MWh					
Added incremental demand	kW	9,635	9,924	10,222	10,529	10,845
Total, revenues due to incremental demand	**US$**	**361,328**	**372,168**	**383,333**	**394,833**	**406,677**
Total, Benefits	**US$**	**449,596**	**460,436**	**471,601**	**483,101**	**494,945**

	unit	2040	2041	2042
Reduction in Generation Costs				
Fixed costs	US$/year	31,960	31,960	31,960
Variable costs	US$/year	56,308	56,308	56,308
Total, costs avoided due to reduction in generation	**US$**	**88,268**	**88,268**	**88,268**
Increase in Electricity Supplied				
Price per MWh	US$/MWh			
Added incremental demand	kW	11,170	11,505	11,850
Total, revenues due to incremental demand	**US$**	**418,878**	**431,444**	**444,387**
Total, Benefits	**US$**	**507,146**	**519,712**	**532,655**
NPV Total Benefits	**2,653,699**			

Note: Net present value was calculated assuming a 10 percent discount rate.

Most costs associated with the project are capital expenditures (CAPEX), which would be invested in the first 4 years of the project. Table 5.2 shows the economic cash flow for CAPEX, including the total net present value.

Table 5.2: Economic Cash Flows—Total CAPEX (2020-2023)

	unit	2020	2021	2022	2023
Capital Expenditure (CAPEX)					
Labor and Materials					
Total costs, transmission line 12kV (overhead single circuit)	US$	156,000	468,000	624,000	312,000
Total costs, low voltage systems	US$	34,253	102,758	137,011	68,506
Total costs, labor and materials	**US$**	**190,253**	**570,758**	**761,011**	**380,506**
Overhead					
Total costs, overhead	**US$**	**19,025**	**57,076**	**76,101**	**38,051**
Total, CAPEX	**US$**	**209,278**	**627,834**	**837,112**	**418,556**
NPV Total CAPEX	**1,786,332**				

Note: Net present value was calculated assuming a 10 percent discount rate.

The remaining costs associated with the project are operating expenditures (OPEX), which would be expended every year from 2023 until the end of the project's lifetime in 2042. Table 5.3 shows the economic cash flow for OPEX, including the total net present value.

Table 5.3: Economic Cash Flows—Total OPEX (2020-2042)

	unit	2020	2021	2022	2023	2024
Operating Expenditure (OPEX)						
Total, O&M costs	US$	-	-	-	20,928	20,928
Total, G&A costs	US$	-	-	-	20,928	20,928
Total, OPEX	**US$**	**-**	**-**	**-**	**41,856**	**41,856**

	unit	2025	2026	2027	2028	2029
Operating Expenditure (OPEX)						
Total, O&M costs	US$	20,928	20,928	20,928	20,928	20,928
Total, G&A costs	US$	20,928	20,928	20,928	20,928	20,928
Total, OPEX	**US$**	**41,856**	**41,856**	**41,856**	**41,856**	**41,856**

	unit	2030	2031	2032	2033	2034
Operating Expenditure (OPEX)						
Total, O&M costs	US$	20,928	20,928	20,928	20,928	20,928
Total, G&A costs	US$	20,928	20,928	20,928	20,928	20,928
Total, OPEX	**US$**	**41,856**	**41,856**	**41,856**	**41,856**	**41,856**

	unit	2035	2036	2037	2038	2039
Operating Expenditure (OPEX)						
Total, O&M costs	US$	20,928	20,928	20,928	20,928	20,928
Total, G&A costs	US$	20,928	20,928	20,928	20,928	20,928
Total, OPEX	**US$**	**41,856**	**41,856**	**41,856**	**41,856**	**41,856**

	unit	2040	2041	2042
Operating Expenditure (OPEX)				
Total, O&M costs	US$	20,928	20,928	20,928
Total, G&A costs	US$	20,928	20,928	20,928
Total, OPEX	**US$**	**41,856**	**41,856**	**41,856**
NPV Total OPEX	**294,496**			

Note: Net present value was calculated assuming a 10 percent discount rate.

Given the magnitude of the benefits accrued over the lifetime of the project, the project's viability would not be largely affected by risks, including cost overruns, decreases in demand, changes in the discount rate, and a rise in inflation. Table 5.4 provides an overview of the sensitivity analysis that was carried out to assess the project.

Table 5.4: Sensitivity Analysis

	Economic Benefits NPV (US$)	CAPEX NPV (US$)	OPEX NPV (US$)	IRR (%)	Total NPV (US$)
Overruns					
None	$2,653,699	$1,786,332	$294,496	13.7%	$572,871
25.0%	$2,653,699	$2,232,915	$368,120	10.3%	$52,664
27.5%	$2,653,699	$2,278,125	$375,574	10.0%	$1
Demand decrease					
None	$2,653,699	$1,786,332	$294,496	13.7%	$572,871
10.0%	$2,450,435	$1,786,332	$294,496	12.4%	$369,607
28.2%	$2,080,829	$1,786,332	$294,496	10.0%	$1
Discount rate					
10.0%	$2,653,699	$1,786,332	$294,496	13.7%	$572,871
12.0%	$2,208,997	$1,735,105	$249,233	13.7%	$224,659
Inflation					
No	$2,653,699	$1,786,332	$294,496	13.7%	$572,871
Yes	$2,653,699	$1,904,150	$314,465	12.7%	$435,085

The table above shows that the project would be able to withstand significant cost overruns as well as large decreases in demand for electricity. For example, the project's net present value would remain positive even if the project experiences cost overruns of 27.5 percent and a drop in demand of 28.2 percent.

In addition, the project would be able to stand changes in the discount rate and inflation. If the discount rate increases to 12 percent, the project would still have a positive net present value. This is also the case if the US dollar experiences inflation of 3.6 percent on average each year.[12]

[12] Since the project's budget was determined in US dollars, changes in inflation were linked to the projected US inflation rate. The sensitivity analysis assumed 2.6 percent inflation in 2019, 2.7 percent in 2020, and 3.7 percent for all years after 2020.

6 Conclusions and Recommendations

The Koina Kondre Area Project is economically viable using the assumptions modeled in this study and should be pursued. Assuming a 10 percent discount rate,[13] the net present value of the estimated benefits totals US$2.7, while the net present value of the estimated costs totals US$2.1 million. As a result, the internal rate of return of the project is 13.7 percent.

The project can also withstand significant risks, including cost overruns, decreases in demand, changes in the discount rate, and a rise in inflation. The project can experience cost overruns of up to 27.5 percent, as well as decreases in the demand for electricity of 28.2 percent. The project would also continue having a positive net present value even if the discount rate increases to 12 percent or inflation increases moderately.

[13] This discount rate was approved by the Government of Suriname for the Electricity Sector Plan.

Appendix A—Project Assumptions

This study used several assumptions and criteria to assess the Koina Kondre are project. These included:

- Demand forecast (Appendix A.1)
- Generation Costs (Appendix A.2)
- Distribution and Commercialization Rates (Appendix A.3).

These are presented in detail below.

A.1 Demand Forecast

To estimate total demand for the Koina Kondre area, we used the assumptions presented below.

Residential customers

Given the location of the proposed distribution system, we estimated that initially there were approximately 598 households (residential customers) for the project. According to the Electricity Sector Plan (ESP) prepared for EBS,[14] residential customers consume an average of 4,610kWh each year. Total residential consumption for this area was estimated at 2,770MWh annually. Considering a load factor of 67 percent, total demand was estimated at 470kW.

We assumed that a peak load of 188kW—approximately 40 percent of potential demand—is currently supplied by small diesel generators. These generators are owned and operated by the Ministry of Natural Resources, which covers the total cost of service and does not charge any fees to customers. We calculated the electricity provided by these plants at 263MWh annually, assuming 4 hours of service each day for 1,460 hours a year.

Commercial and industrial customers

We also estimated two recreational centers and five wood concessionaires in the Koina Kondre area. For each commercial and industrial customer, we estimated 400,000kWh in electricity consumption each year. Total consumption was then calculated at 2,800MWh annually. Considering a load factor of 67 percent, total demand was estimated at 480kW. We also assumed that electricity provided to these customers are currently supplied by self-generation or other private generators that are not owned or operated by the Government.

Total demand for all customers

Given these assumptions, we estimated that the potential demand would reach 950kW for all customers. This would result in the consumption of approximately 5,575MWh in year 2023.

We also assumed that demand would increase once there is access to electricity in the area. New housing developments, businesses, and industries would result in accelerated growth and demand for electricity services. We estimated an annual growth rate of 5 percent for the first 10 years of the project and 3 percent thereafter. Table A.1 shows the demand forecast for the project from 2023 to 2042.

[14] The ESP was presented by Castalia to the Inter-American Development Bank and the Ministry of Natural Resources in Suriname in November 2018.

Table A.1: Demand Forecast for Project (2023-2042)

	Residential		Commercial & Industrial		Total	
Year	Capacity (kW)	Energy (MWh)	Capacity (kW)	Energy (MWh)	Capacity (kW)	Energy (MWh)
2023	470.0	2,758.5	480.0	2,817.2	**950.0**	**5,575.7**
2024	493.5	2,896.5	504.0	2,958.1	**997.5**	**5,854.5**
2025	518.2	3,041.3	529.2	3,106.0	**1,047.4**	**6,147.3**
2026	544.1	3,193.3	555.7	3,261.3	**1,099.7**	**6,454.6**
2027	571.3	3,353.0	583.4	3,424.3	**1,154.7**	**6,777.3**
2028	599.9	3,520.7	612.6	3,595.6	**1,212.5**	**7,116.2**
2029	629.8	3,696.7	643.2	3,775.3	**1,273.1**	**7,472.0**
2030	661.3	3,881.5	675.4	3,964.1	**1,336.7**	**7,845.6**
2031	694.4	4,075.6	709.2	4,162.3	**1,403.6**	**8,237.9**
2032	729.1	4,279.4	744.6	4,370.4	**1,473.8**	**8,649.8**
2033	765.6	4,493.3	781.9	4,588.9	**1,547.4**	**9,082.3**
2034	788.5	4,628.1	805.3	4,726.6	**1,593.9**	**9,354.8**
2035	812.2	4,767.0	829.5	4,868.4	**1,641.7**	**9,635.4**
2036	836.6	4,910.0	854.4	5,014.5	**1,690.9**	**9,924.5**
2037	861.7	5,057.3	880.0	5,164.9	**1,741.7**	**10,222.2**
2038	887.5	5,209.0	906.4	5,319.8	**1,793.9**	**10,528.9**
2039	914.1	5,365.3	933.6	5,479.4	**1,847.7**	**10,844.7**
2040	941.6	5,526.2	961.6	5,643.8	**1,903.2**	**11,170.1**
2041	969.8	5,692.0	990.4	5,813.1	**1,960.3**	**11,505.2**
2042	998.9	5,862.8	1,020.2	5,987.5	**2,019.1**	**11,850.3**

A.2 Generation Costs

The generation cost for the Koina Kondre area were estimated assuming that the units used to generate electricity were reciprocating internal combustion engines (RICE) using diesel. We assumed that the units had the following characteristics:

- Nominal capacity: 250kW
- Efficiency: 9,050Btu/kWh
- Average availability: 65%
- Cost of capital investment: US$1,400/kW
- Fixed operation and maintenance costs: US$36/kW-year

- Non-fuel variable operation and maintenance costs: US$15/MWh
- HFO price: US$22/MMBtu.

The benefits provided by the reduction in installed capacity were quantified in terms of capital costs of the generation unit per kW-year, plus fixed operating and maintenance costs. The benefits associated with the reduction of energy produced were quantified in terms of the variable generation costs per MWh, which cover the variable operation and maintenance costs and the costs associated with the fuel consumption.

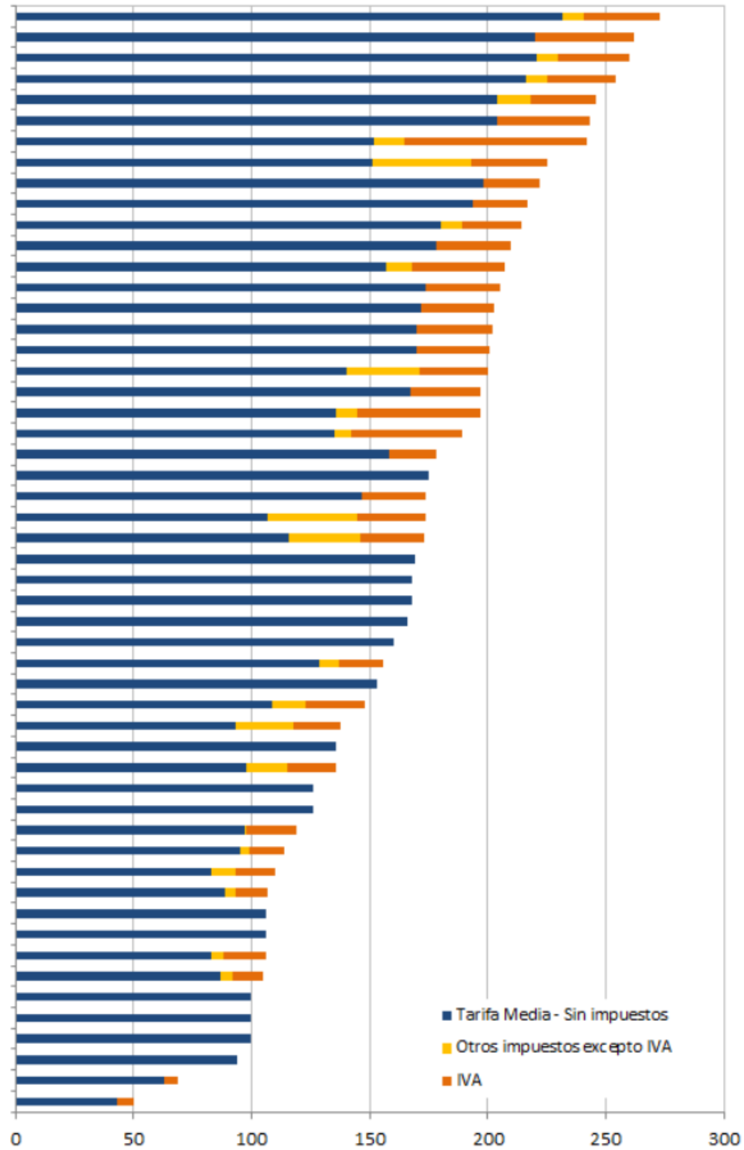
For the purposes of cost leveling, a discount rate of 7.18 percent (equal to the WACC for EBS) and an equipment useful life of 20 years were considered. With these assumptions, the generation costs associated with the reduction of installed capacity are US$170/kW-year and those associated with the reduction of energy generated are US$214.1/MWh.

A.3 Distribution and Commercialization Rates

Electricity tariffs in Suriname currently do not reflect the total cost of providing service efficiently. These distortions cannot be attributed to the project, so our evaluation was done considering the average electricity tariffs in neighboring countries in Latin America.

According to the Commission of Integrated Regional Energy (CIER—*Comisión de Integración Energética Regional*), average residential tariffs were approximately US$150 per MWh in 2018. This value was calculated using information from 40 companies in Latin America. Since commercial and industrial customers tend to have higher tariffs, we used this as a conservative proxy for the tariff charged to all customers. Figure A.1 provides an overview of these residential tariffs below.

Figure A.1: Average Tariff for Residential Customers in Latin American Countries (US$/MWh)



Source: CIER. 2019. "Tarifas Eléctricas en Distribución para Clientes Regulados 2018" Accessed 4 June 2019. http://ciertarifas.org/informes_pasados/tarifas-electricas-informe-ejecutivo-2018/

These tariffs include the costs associated with the generation, transmission, distribution, and commercialization of electricity, as well as the cost of managing the system. Traditionally, distribution and commercialization services represent between 20 and 30 percent of the total tariff. Assuming that these services represent 25 percent of an average tariff of US$150/MWh, we valued the distribution and commercialization of electricity at US$37.5/MWh for all customers.

Appendix B—Ampacity Calculation SAX-W 70

The ampacity calculation for the SAX-W 70 is provided below:

> Bare Wire Sizing v3.0.0.1 - (c) 1983-2016 Power Analytics Corporation.
>
> Date: 05/24/2019 08:44:15
>
> Node ID: SAX-W 70
>
> Description: SURINAM CONDITIONS
>
> Application: Ampacity Calculation
>
> Conductor Type: Aluminum
>
> Unit: Metric
>
> Conductor Diameter: 0.5630 cm
>
> Resistance at 25º C: 0.4309 Ω
>
> Resistance at 75º C: 0.5042 Ω
>
> Maximum Temperature: 75º C
>
> Ambient Temperature: 50º C
>
> Ambient Wind Speed: 2.000 m/s
>
> Coefficient of Emissivity: 0.500
>
> Coefficient of Solar Absorption: 0.500
>
> Line Elevation above Sea Level: 40 m
>
> Line Direction: NORTH-SOUTH
>
> Line Latitude: 55.00 degree
>
> Local Sun Time: 13:00
>
> Atmospheric Condition: CLEAR
>
> Convection Heat Loss (Qc): 8.404 W/m
>
> Radiated Heat Loss (Qr): 0.578 W/m
>
> Solar Heat Gain (Qs): 0.713 W/m
>
> **Conductor Ampacity: 373 A**

Appendix C—Financial Cash Flows

The Koina Kondre Area Project would generate revenue and would therefore be financially viable. The project would result in incremental energy that EBS could sell throughout the 20-year lifetime. The financial analysis for the project considers operating expenditures (OPEX) as well total capital expenditures (CAPEX). Total CAPEX includes the return of the investment—the actual cost of labor and materials—and the return on the investment—the costs incurred to finance the project.

The return on the investment is calculated assuming the project would incur interest during construction (IDC) costs equal to LIBOR in June 2019 (2.56 percent), and that the project would be financed with an IDB loan. The loan would have a 5-year grace period to begin capital repayment, a 20-year tenor, and an interest rate equal to LIBOR forecasted until June 2021 and assumed fixed until 2047.

As a result, the net present value of the project (NPV) would be US$143,725 if debt service is considered. The internal rate of return for the project would be approximately 8.0 percent. Table C.1 presents the financial cash flow from 2020 until 2048, assuming a weighted average cost of capital (WACC) of 7.2 percent.

Table C.1: Financial Cash Flows (2020-2048)

		unit	2020	2021	2022	2023	2024
Cash Flow	**NPV**	**US$**	**(209,278)**	**(633,192)**	**(858,679)**	**(294,871)**	**177,689**
Operating Revenue	$2,714,394	US$	-	-	-	209,090	219,545
OPEX	($380,632)	US$	-	-	-	(41,856)	(41,856)
CAPEX	($1,922,836)	US$	(209,278)	(633,192)	(858,679)	(462,105)	-
Interest Paid	($267,201)	US$	-	-	-	-	-

		unit	2025	2026	2027	2028	2029
Cash Flow	**NPV**	**US$**	**188,666**	**200,192**	**212,295**	**159,734**	**176,340**
Operating Revenue	$2,714,394	US$	230,522	242,048	254,151	266,858	280,201
OPEX	($380,632)	US$	(41,856)	(41,856)	(41,856)	(41,856)	(41,856)
CAPEX	($1,922,836)	US$	-	-	-	-	-
Interest Paid	($267,201)	US$	-	-	-	(65,269)	(62,005)

		unit	2030	2031	2032	2033	2034
Cash Flow	**NPV**	**US$**	**193,614**	**211,588**	**230,297**	**249,779**	**263,260**
Operating Revenue	$2,714,394	US$	294,211	308,922	324,368	340,586	350,804
OPEX	($380,632)	US$	(41,856)	(41,856)	(41,856)	(41,856)	(41,856)
CAPEX	($1,922,836)	US$	-	-	-	-	-
Interest Paid	($267,201)	US$	(58,742)	(55,478)	(52,215)	(48,952)	(45,688)

		unit	2035	2036	2037	2038	2039
Cash Flow	**NPV**	**US$**	**277,047**	**291,151**	**305,579**	**320,343**	**335,451**
Operating Revenue	$2,714,394	US$	361,328	372,168	383,333	394,833	406,677
OPEX	($380,632)	US$	(41,856)	(41,856)	(41,856)	(41,856)	(41,856)
CAPEX	($1,922,836)	US$	-	-	-	-	-
Interest Paid	($267,201)	US$	(42,425)	(39,161)	(35,898)	(32,634)	(29,371)

		unit	2040	2041	2042	2043	2044
Cash Flow	**NPV**	**US$**	**350,915**	**366,744**	**382,951**	**(16,317)**	**(13,054)**
Operating Revenue	$2,714,394	US$	418,878	431,444	444,387	-	-
OPEX	($380,632)	US$	(41,856)	(41,856)	(41,856)	-	-
CAPEX	($1,922,836)	US$	-	-	-	-	-
Interest Paid	($267,201)	US$	(26,107)	(22,844)	(19,581)	(16,317)	(13,054)

		unit	2045	2046	2047
Cash Flow	**NPV**	**US$**	**(9,790)**	**(6,527)**	**(3,263)**
Operating Revenue	$2,714,394	US$	-	-	-
OPEX	($380,632)	US$	-	-	-
CAPEX	($1,922,836)	US$	-	-	-
Interest Paid	($267,201)	US$	(9,790)	(6,527)	(3,263)
NPV	**143,725**	**US$**			
IRR	**7.97%**	**%**			

T: +1 (202) 466-6790
F: +1 (202) 466-6797
1747 Pennsylvania Avenue NW
Suite 1200
WASHINGTON DC 20006
United States of America

T: +1 (646) 632-3770
F: +1 (212) 682-0278
200 Park Ave
Suite 1744
NEW YORK, NY 10166
United States of America

T: +61 (2) 9231 6862
Level 1, 27-31 Macquarie Place
SYDNEY NSW 2000
Australia

T: +64 (4) 913 2800
F: +64 (4) 913 2808
Level 2, 88 The Terrace
PO Box 10-225
WELLINGTON 6143
New Zealand

T: +57 (1) 646 6626
F: +57 (1) 646 6850
Calle 100 No. 7-33
Torre 1, Piso 14
BOGOTÁ
Colombia

T: +33 (1) 73 44 26 97
F: +33 (1) 73 44 26 01
6, Rue Duret
PARIS 75116
France

------------- www.castalia-advisors.com