

Pricing, Rates, & Strategic Planning



**VIRGIN ISLANDS
WATER & POWER
AUTHORITY**

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October 19, 2021

Mr. Donald Cole
Executive Director
Virgin Islands Public Services Commission
P.O. Box 40
St. Thomas, Virgin Islands 00804

Subject: **Virgin Islands Public Services Commission Docket 289 (LEAC)**

Dear Mr. Cole:

The Virgin Islands Water and Power Authority (The Authority) hereby submits a petition for the Electric Systems Levelized Energy Adjustment Clause (LEAC) charges to be applied to all bills rendered on or after January 1, 2022. The periods covered are January 1, 2022 – June 30, 2022. This petition is based on the historical and projected information as outlined in detail in Attachment A for the Electric System. The attachment is included in this filing. In the attachment, the proposed LEAC of \$0.202459 /kWh (20.25¢/kWh) represents an increase in the proposed LEAC rate as a result of rising fuel costs.

1. Electric LEAC Charge Methodology

The methodology used to compute the proposed Electric LEAC charge for this filing is essentially the same as the methodology used to compute the approved Electric LEAC charge that is currently in effect utilizing the projected energy requirements from the Electric System generating unit dispatch. The following narrative and exhibits comply with the Minimum Filing Requirements for the Electric Levelized Energy Adjustment Clause as described in the Virgin Islands Public Services Commission (PSC) Order No. 39/2015, Docket No. 614.

1.1 Description of Proposed LEAC Rates

As derived from Table A-1 of Attachment A, the Electric LEAC charge proposed for the period January – June 2022 is 20.25 ¢/kWh. The Authority is requesting rate relief for current fuel costs and other fuel related charges. This increase does not include any deferred fuel costs.

Table A-1 - Electric LEAC Rate Components

Line No.	Units	Semi-Annual Analysis			
		Historical	Current as Approved	Proposed LEAC	
		Jan - June 2021	Jul - Dec 2021	Jan - Jun 2022	
LEAC Rate Component					
1	Current Fuel Cost Portion of LEAC	¢/kWh	20.60	16.63	19.61
Other Charges					
2	Regulatory Costs (Dkt 289)	¢/kWh	0.02	0.03	0.03
3	Renewable Energy Cost	¢/kWh	0.24	0.23	0.24
4	Ultra Pure Water Charge	¢/kWh	0.32	0.29	0.32
5	Plant Repair RO Contract	¢/kWh	0.05	0.04	0.04
6	Total Other Charges	¢/kWh	0.63	0.58	0.63
7	Normalized Recovery of Deferred Fuel Balance (Credit for Prior Period Over Recovery)	¢/kWh	6.29	0.00	0.00
8	Charge for Prior Period Under Recovery	¢/kWh			
9	Total LEAC Rate	¢/kWh	14.94	17.21	20.25
10	Total LEAC Rate	\$/kWh	0.149417	0.172125	0.202459

1.2 Impact of the Rate Adjustment on Ratepayers' Bills

The net effect of the proposed change in the Electric LEAC charge on the customers' monthly bills is shown in Table 1:

Table 1
Impact of Proposed LEAC Charge on Typical Electric Bills

Customer Type	Assumed Monthly Energy Use	Projected Monthly Effect on Bills to Customers			
		Approved Bill	Proposed LEAC	Increase	Percent Change
	kWh		\$	\$	%
Residential	400	163.10	\$173.41	\$10.31	6.32%
Commercial	1,200	553.67	\$584.61	\$30.94	5.59%
Large Power	25,000	10,193.66	\$10,838.23	\$644.57	6.32%

1.3 Statement of the Authority's Position on Amortization Period for Deferred Fuel

As of June 2019, the deferred fuel under recovery balance of \$28,750,992.

For As reflected in Attachment A- Electric System LEAC filing workbook, the Authority's proposed rate excludes the deferred fuel balance from our most current audited financials (FY 2019), and the total deferred fuel balance is in excess of \$41M as of August 2021.

1.4 Material Changes in Operations That Support the Requested Rate Adjustment

A discussion of the operational parameters that impact the proposed LEAC charge adjustment is provided below:

(a) Fuel Price

The fuel prices used in the proposed LEAC charge are drawn from the average prices reported in publicly available indices, plus allowances for transportation.

Fuel costs are projected for the semi-annual period using average heat rates calculated by plant production personnel; actual average heat content of fuel burned during the historical periods; energy production from the historical periods modified only for differences in projected reverse osmosis (RO) energy requirements in the semi-annual period; and the projected fuel mix (proportion of No. 2 Fuel Oil and LPG). The projected fuel prices are based on the October 12th, 13th, and 14th, 2021 No. 2 NYMEX Heating Oil prices and Propane Non LDH Mt Belvieu as reported by the Chicago Mercantile (CME) Group and. The detailed fuel prices and calculations are found on Table A-5 of Attachment A.

The projected fuel prices included in the LEAC charge for the January through June 2022 period are 41% percent higher for No. 2 Fuel Oil and 24% percent higher for LPG than the actual prices for the historical period January through June 2021.

Table 2
St. Thomas Power Plant Projected Unit Fuel Type, Dispatch Mode, and Availability
(January through June 2022)

St. Thomas, Randolph Harley Power Plant				Availability					
Resource Name	Resource ID	Fuel Type	Dispatch Mode	JAN	FEB	MAR	APR	MAY	JUN
U14	STT_RH_GT_14_Diesel	Diesel	OUT	READY	READY	READY	READY	READY	READY
U15 Diesel	STT_RH_GT_15_Diesel	Diesel	OUT	READY	READY	READY	READY	READY	READY
U15 LPG	STT_RH_GT_15_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
U23	STT_RH_GT_23_Diesel	Diesel	ECON	READY	READY	READY	READY	READY	READY
GE U27	STT_RH_GT_27_Diesel	Diesel	ECON	READY	READY	READY	READY	READY	READY
Wartsila 1	STT_RH_RICE_1_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Wartsila 2	STT_RH_RICE_2_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Wartsila 3	STT_RH_RICE_3_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Wartsila 4 LPG	STT_RH_RICE_4_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 5 LPG	STT_RH_RICE_5_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 6 LPG	STT_RH_RICE_6_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 7 LPG	STT_RH_RICE_7_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 8 LPG	STT_RH_RICE_8_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 4 Diesel	STT_RH_RICE_4_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 5 Diesel	STT_RH_RICE_5_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 6 Diesel	STT_RH_RICE_6_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 7 Diesel	STT_RH_RICE_7_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Wartsila 8 Diesel	STT_RH_RICE_8_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Bovoni PV	STT_Bov_PV_1	RE	FIXED	READY	READY	READY	READY	READY	READY
Port Authority PV	STT_PA_PV_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Donoe PV	STT_Don_PV_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Cruz Bay PV	STJ_CRZ_PV_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE

Power Generation, St. Thomas:

- Unit 14 will be utilized as an additional standby unit for the January through June 2022 periods. Its primary responsibilities include black start operation and standby generation when other units are unavailable (i.e., U23 or U15). Unit 14 is not scheduled to be included as part of the daily unit dispatch rotation for the upcoming period.
- The Wartsila Reciprocating Internal Combustion Engine (RICE) Units 1, 2 and 3 are expected to be online and fully operational for the entirety of the January through June 2022 period. These units will utilize LPG as the singular fuel source.
- Unit 23 and leased GE Unit 27 will be utilized in tandem as the primary baseload units during the January through June 2022 period. The remainder of the load demand will be met by the Wartsila engines as previously mentioned. Currently, Units 23 & leased GE Unit 27 are configured to operate on No. 2 fuel only.

- CT Unit 15 will operate on LPG as the primary fuel and No. 2 Fuel Oil as back-up/emergency fuel. It will be undergoing an HGP inspection between January and June of 2022 and return to service operating primarily on LPG. (Project dependent on available funding)

Table 3
St. Croix Power Plant Projected Unit Fuel Type, Dispatch Mode, and Availability
(January through June 2022)

St. Croix, Estate Richmond Power Plant				Availability					
Resource Name	Resource ID	Fuel Type	Dispatch Mode	JAN	FEB	MAR	APR	MAY	JUN
U20 Diesel	STX_ER_GT_20_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
U20 LPG	STX_ER_GT_20_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
U17 Diesel	STX_ER_GT_17_Diesel	Diesel	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
U17 LPG	STX_ER_GT_17_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
U19	STX_ER_GT_19_Diesel	Diesel	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 1	STX_ER_AGG_1_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 2	STX_ER_AGG_2_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 3	STX_ER_AGG_3_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 4	STX_ER_AGG_4_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 5	STX_ER_AGG_5_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 6	STX_ER_AGG_6_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 7	STX_ER_AGG_7_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 8	STX_ER_AGG_8_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 9	STX_ER_AGG_9_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 10	STX_ER_AGG_10_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 11	STX_ER_AGG_11_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 12	STX_ER_AGG_12_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 13	STX_ER_AGG_13_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 14	STX_ER_AGG_14_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 15	STX_ER_AGG_15_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 16	STX_ER_AGG_16_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 17	STX_ER_AGG_17_LPG	LPG	ECON	READY	READY	READY	READY	READY	READY
Aggreko Engine 18	STX_ER_AGG_18_LPG	LPG	OUT	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Spanish Town Solar	STX_PV_2	RE	FIXED	READY	READY	READY	READY	READY	READY
Adventure PV	STX_Advent_PV_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
HERA PV	STX_HERA_PV_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE
Longford Wind	STX_LF_Wd_1	RE	FIXED	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE	OFFLINE

Power Generation, St. Croix:

To meet the forecasted demand for St. Croix, the Authority plans to utilize the Aggreko power generation facility, which entered commercial service in April 2019 operating on LPG only, in concert with a rotation of Unit 20 and Unit 17 in simple cycle mode on LPG. Of the remaining available units, Unit 19 will operate as the designated standby unit on diesel.

(b) Energy Sales

Energy sales are projected for the semi-annual period based on projected energy requirements derived in the dispatch methodology, allocated based on the number of days in each month for the period, and the net of Reverse Osmosis (RO) water plant energy requirements. This production level is then reduced for losses and internal Authority uses based on the average actual losses and uses over the 12-months ended with the historical period but is to be no greater than 6.6% as per PSC order 42/2020.

(c) Credits from Water Department

The rate used for computing credits to the Electric Department from the Water Department related to energy used in the RO plants is calculated using a method agreed upon with the Commission's technical consultant prior to the LEAC filing for the rates placed into effect on October 1, 2013.

(d) Solar Energy Production

Included in this LEAC Filing is the anticipated cost to be recovered for the Spanish Town Solar facility on St. Croix. The USVI Solar Facility on St. Thomas is still not in operation for the proposed period. Semi-Annual costs for the Spanish Town Solar Facility were calculated using a projected production based on the current operational capability of the site and the product price for that contract year as specified in its Power Purchase Agreement (PPA). The historical information is based on the actual data for the period. The site has been producing at its capacity level for a few months.

1.5 Statement of Changes in Maintenance Management Planning and Plant Conditions:

The following are changes in maintenance management planning and plant conditions that occurred during the historical period and that are projected to occur during the period January through June 2022.

St. Thomas

Changes in Maintenance Management Planning

At this time, Unit 23 will be utilized as a stand-by unit through the next LEAC period operating on No.2 Fuel Oil only.

Unit 27, which GE now operates, now functions as a primary unit to meet peak demands and dispatched when other LPG fired units are not available for operational use. After performing an economic evaluation on GE original schedule to convert the unit to LPG by March 2022, it was determined that the benefits of this conversion would not yield the anticipated saving, since the conversion period increased from 20 weeks to 32 weeks and would put this LPG operation in commercial operation 6 months before the 36 MW with BESS Wartsila project comes into commercial operation

Based on analysis, the Authority anticipates the most viable alternatives are the installation of the 36MW Wartsila units which are extremely efficient and will include battery storage, the rebuilding of the Donoe solar field, and recently approved wind power project with Advanced Power.

1.6 Statement of Fuel Supply, Fuel Diversity, and Hedging Programs

Fuel Supply

The LPG delivery and storage infrastructure and the power plant safety requirements are in full operation at both power plants. VITOL has increased the delivery cost of propane from \$0.33 to \$0.38. The Authority may also request (pending board approval) in the near future the collection of the additional five cents per gallon of LPG that was implemented pursuant to the Amended and Restated LPG Vitol Agreement that increased in August 2020. Although this expenditure is not currently recognized as deferred fuel from a rates perspective (no historical rates have been requested to cover the costs), its financial impact to the Authority is a direct result of fuel related costs and should be recognized and included in LEAC rates.

Fuel Diversity

Apart from Units 14, 23, the GE Unit 27 at the St. Thomas Power Plant, and Unit 19 at the St. Croix Power Plant, all the Authority's units can operate on LPG. Table 4 illustrates the projected level of fuel diversity at the St Thomas and St Croix Power Plants based on the available capacity of each unit for the period January - June 2022.

**Table 4
Plant Fuel Diversity**

Fuel Type	St. Thomas Power Plant	St. Croix Power Plant
LPG Only	32%	99%
No. 2 Fuel Oil Only	68%	1%

1.7 Statement Regarding Status of Alternative Energy Supply and Level of Compliance with any Legislative Mandates

The Authority received 3,902,9131kWh of electric energy from the Spanish Town, St. Croix Solar Plant for the period January through June 2021. The facility has an estimated annual production of 8,218,954 kWh for the eighth year. As agreed, upon in the PPA, the Authority is charged \$.165/kWh for the eighth year of production.

Since Hurricanes Irma and Maria in September 2017, the Authority received no electric energy from the USVI Solar I Solar Facility on St. Thomas. Table 5 reflects the renewable grid penetration (including Net Metering) as of December 2020.

**Table 5
 Renewable Energy Portfolio**

Renewable Energy Portfolio Standards	
Project Type	Size (MW)
St. Thomas	
Solar (PV)	0.45
Net Metering	9.92
St. Croix	
Solar (PV)	4.00
Net Metering	<u>5.77</u>
Total Renewables:	20.14
Average Load (MW)	
St. Thomas	51.50
St. Croix	<u>36.40</u>
Total Average Load:	87.90
System Penetration (% of Load):	22.91 %

As reflected in Table 5, with the inclusion of the Net Metering Program, the Authority is well on the way towards achieving the Renewable Portfolio Standards (RPS) as per Act 7075: 20% by 2015, 25% by 2020 and 30% by 2025.

Because of the devastating impact of Hurricanes Irma and Maria in September 2017, the Donoe Solar Facility on St. Thomas remains completely out of service. The Donoe Solar facility contract was assigned to BMR. The PSC approved the BMR Power Purchase Agreement.

Advance Power for the output of a 9.0 MW wind energy facility on St Thomas received board approval in March 2021. A rate of 17cents / kWh was negotiated at that time.

1.8 Statement of the Degree to Which the Authority’s Planned Generation Resource Additions and Retirements are Consistent with or Differ from the Most Recently Approved IRP

The approved 2016 IRP includes recommendations for the implementation of a Near Term Generation Plan (NTGP). The initial plan included the following recommendations:

- a. A lease to own arrangement for three 7 MW Wartsila Generating Units
- b. A short-term lease agreement with APR for an additional rental unit that will operate on LPG and No. 2 Fuel Oil
- c. Purchase of a 22 MW Siemens Engine

After further analysis was conducted, it was determined that the Siemen’s unit would destabilize the electric grid. The Near-Term Generation Plan was amended as follows:

- a. Procurement of three 7 MW Wartsila Generating Units (Completed)

- b. A short-term lease extension of Unit 27 with GE

The Authority has made great strides as follows in implementing the recommendations based in the updated IRP:

- a. Installed the first three Wartsila RICE units and was placed into commercial operation in June 2019. While the Authority will own these units, payments are still required, and legal action is taking place at this time.
- b. Entered in to lease with GE for Unit 27 until the new 36MW Wartsila units are online in July of 2022. The new Wartsila Units are now expected to be on-line December 2022.

The Authority has finalized and submitted its 2019 IRP to the Public Service Commission.

1.9 Statement and Status of Equipment Purchased or Leased and Plans for Modification of the Equipment and Implementation of the Equipment into the Systems and the Impact of Such Implementation

Unit 27- Temporary Unit

The Authority ended its lease agreement with APR for Unit 27. A new lease agreement was established with General Electric, who is the owner of Unit 27, on June 4, 2020.

Wartsila Units

On March 15, 2017, the Authority executed a contract with Wartsila for the engineering, procurement, and construction of a 21 MW power generating facility at the site of the existing power plant facility located in St. Thomas. The three 7.0 MW are installed and operating at full capacity, which came online and in commercial operation in June 2019. The Authority has entered into a contract with Wartsila for an additional 36MW of new generation with battery storage included. This is project is currently in the design and engineering process and projected to be completed and online by December 2022.

2 Summary of Electric LEAC Rate Computation

The following is an excerpt from Table A-1 of Attachment A that summarizes the components of the proposed Electric LEAC.

Table 6
Electric LEAC Charge Components

Key Considerations and Assumptions

The following Table 6 and 7 from Attachment A summarizes key assumptions and considerations underlying and resulting from the LEAC Rate calculations.

Table A-1 - Electric LEAC Rate Components

		Semi-Annual Analysis		
Line No.	Units	Historical	Current as Approved	Proposed LEAC
		Jan - June 2021	Jul - Dec 2021	Jan - Jun 2022
LEAC Rate Component				
1	Current Fuel Cost Portion of LEAC	¢/kWh 20.60	¢/kWh 16.63	¢/kWh 19.61
Other Charges				
2	Regulatory Costs (Dkt 289)	¢/kWh 0.02	¢/kWh 0.03	¢/kWh 0.03
3	Renewable Energy Cost	¢/kWh 0.24	¢/kWh 0.23	¢/kWh 0.24
4	Ultra Pure Water Charge	¢/kWh 0.32	¢/kWh 0.29	¢/kWh 0.32
5	Plant Repair RO Contract	¢/kWh 0.05	¢/kWh 0.04	¢/kWh 0.04
6	Total Other Charges	¢/kWh 0.63	¢/kWh 0.58	¢/kWh 0.63
7	Normalized Recovery of Deferred Fuel Balance (Credit for Prior Period Over Recovery)	¢/kWh 6.29	¢/kWh 0.00	¢/kWh 0.00
8	Charge for Prior Period Under Recovery	¢/kWh	¢/kWh	¢/kWh
9	Total LEAC Rate	¢/kWh 14.94	¢/kWh 17.21	¢/kWh 20.25
10	Total LEAC Rate	\$/kWh 0.149417	\$/kWh 0.172125	\$/kWh 0.202459

Table 7
Key Considerations and Assumptions

Table A-1S - Key Considerations		Semi-Annual Analysis			
		Historical	Current as Approved	Proposed LEAC	
Line No.	Units	Jan - June 2021	Jul - Dec 2021	Jan - Jun 2022	
1	LEAC Rate	¢/kWh	14.94	17.21	20.25
	Key Components				
2	Current Fuel Costs	¢/kWh	20.60	16.63	19.61
3	Deferred Fuel Amortization	¢/kWh	6.29	0.00	0.00
4	All Other	¢/kWh	(11.95)	0.58	0.63
5	Total LEAC	¢/kWh	14.94	17.21	20.25
	Energy Volumes				
6	Energy Sales	MWh	268,135	304,462	294,600
7	% Higher / Lower than Proposed Period	%	-9.0%	3.3%	
8	Energy Production	MWh	317,157	325,957	342,303

Electric LEAC Differential Analysis

For the proposed LEAC filing, the St. Croix plant will be burning LPG as its primary fuel source. The projection includes 1,708,703 MMBtu of LPG and 1,198 MMBtu of No. 2 Fuel Oil consumed during the period. For the St. Thomas Plant, the projection includes 773,563 MMBtu of LPG and 1,632,722 MMBtu of No. 2 Fuel Oil consumed during the period.

The Authority continues to place a very high priority on all activities aimed at reducing the consumption of fuel per kWh of energy provided to our customers such as the diversification of fuel resources that would lower the total cost of fuel, the streetlight program, and the implementation of renewable resources.

The total production for the proposed period includes 4,369 MWh from St. Croix’s solar energy and 1,250 MWh from St. Thomas’s solar energy.

Additional Information

Glencore Fuel Supply Contract

The current contract with Glencore for the supply of No.2 Fuel Oil expired on December 31, 2020. The terms of this contract incorporated the option to extend for an additional 12-month period. The Authority has entered into its 7th contract extension at this time. The Authority will continue to have discussions in regard to the next steps with respect to a supplier for No. Fuel Oil.)

Plant Efficiency

For the January through June 2021 period, the Authority realized higher than projected heat rates. Table 8 provides a month-by-month comparison of the forecasted verses the actual heat rates over the historic period for the St. Thomas/St. John district. The higher delta is a result of the limited availability of more efficient and cost-effective generation assets at the Harley facility. The absence of APR Unit 25 and Unit 26 has left the Authority with no other choice but to operate the larger U23 at inefficient loading while, relying heavily on Unit 14 for emergency generation capacity. This resulted in a less-than-optimum generation dispatch throughout the January through June 2021 period.

**Table 8
 Forecasted vs. Actual Total Plant Efficiency Comparison – St. Thomas**

Month (2021)	Forecasted Heat Rate (Btu/kWh)	Actual Heat Rate (Btu/kWh)	Delta (Btu/kWh)	Delta (%)
January	12,626	13,029	403	3.1%
February	10,611	13,731	3,120	22.7%
March	10,513	12,863	2,350	18.3%
April	10,806	12,997	2,191	16.9%
May	10,839	12,701	1,862	14.7%
June	10,958	13,443	2,485	18.5%

**Indicates that the delta percentage is outside of the ±5% tolerance range.*

For the January through June 2021 period, the St. Croix power station realized historic heat rate values that were more in-line with the projected heat rates when compared to prior periods. Table 9 provides a month-by-month comparison of the forecasted verses the actual heat rates. The slight variances during the March and April months are the direct result slight changes to the generation dispatch rotation to accommodate for maintenance on propane fired units.

Table 9
Forecasted vs. Actual Total Plant Efficiency Comparison – St. Croix

Month (2021)	Forecasted Heat Rate (Btu/kWh)	Actual Heat Rate (Btu/kWh)	Delta (Btu/kWh)	Delta (%)
January	14,886	15,397	511	3.3%
February	14,606	14,864	258	1.7%
March	13,715	14,844	1,129	7.6%
April	13,735	15,523	1,788	11.5%
May	13,984	14,340	356	2.5%
June	14,447	14,358	(89)	-0.6%

**Indicates that the delta percentage is outside of the ±5% tolerance range.*

2.1 Statement of Challenges to Provision of Efficient and Cost-Effective Generation and Identification of Solutions or Needed Assistance from the Commission

The greatest challenge to the Authority continues to be inadequate cash flow. In order to meet critical needs and continuing operations, the Authority secured payment arrangements with critical vendors and suppliers. Additionally, the Authority sought and received federal assistance after the storms through the Federal Emergency Management Agency (FEMA) grant program and the Community Disaster Loan (CDL) program. However, both the grant program and the CDL program only provide the financial assistance to address the Authority’s post storm needs. As a result of the Covid-19 pandemic, the Authority was granted an extension on re-payment of the CDL loan. On October 1, 2021, the Government House of the Virgin Islands reported the recent passage of the spending bill approved in congress and signed into law by President Biden allowed forgiveness of disaster loans received by the Virgin Islands government and its entities. This included the forgiveness of a \$94.5 million dollar loan the Authority was responsible for.

The current financial condition has forced the Authority to sometimes defer repairs and maintenance to the generating units. The lack of sufficient cash flow has resulted in a practice of paying for immediate critical needs and deferring other needs until there is sufficient cash on hand. The Authority has also been unable to pay for the remaining amounts owed for the first 3 Wartsila units. The Wartsila units are currently the most efficient units in the St .Thomas Power Plant. Unfortunately, there is not sufficient cash flow to pay the outstanding balance of approximately \$21 million. The Authority is still actively pursuing a financing deal along utilizing the fuel tax to pay for the outstanding balances owed to minimize any impact to the ratepayer.

The impact of the Authority’s cash position is reflected in the high negative working capital balance as shown in Table 10. As of June 2021, the Authority’s working capital balance was approximately negative \$335,152 million.

Table 10
Working Capital Balance



Supplementing this filing is the fuel cash analysis as summarized in Table 11 and which details the actual cash flow of the LEAC revenues. The fuel cash analysis reflects that for the 6-month period ending June 2021, the Authority’s billed LEAC charges were \$87,546,298.55. The actual LEAC collections were \$82,973,371.12 (an unfavorable variance of \$4,572,927.43.) This unfavorable difference is due to the Covid-19 pandemic which has caused a reduction in collections as the Authority had just reinstated the disconnection policy after a 10-month suspension and delinquent customers were granted payment plans to assist them in bringing their accounts current. The Authority was billed \$103,765,248.33 for fuel purchases during this period of time resulting in an under-recovery of (\$20,791,877.21)

Table 11
LEAC Summary for Period January 2021 – June 2021

LEAC Billed	\$ 87,546,298.55
LEAC Collected	\$ 82,973,371.12
Difference	(\$ 4,572,927.43)
Total LEAC Collected	\$ 82,973,371.12
Under collection (Disconnect Period)	
Fuel Purchases	103,765,248.33
Revenue Over/Under Collected (10mo)	(\$20,791,877.21)

Exhibits to the Electric LEAC Petition

- 2.2 The most recent consultant report showing the calculations based upon the fuel-pricing index included in the Authority's contracts.**
- 2.3 Annual Electric System LEAC audits with explanation and reconciliation of the figures provided in the financial reports.**

Currently, the last audited financial statements are for FY 2019. The 2018 Audited Financial Statements were completed by BDO in June 2020 and the FY 2019 Audited Financial Statements were completed by BDO in July 2021. The Authority is extremely confident in our analysis of LEAC and deferred fuel balances and will respectfully ask that the PSC accept our deferred fuel balance filed with our semi-annual LEAC filings. (Previously Provided)

In addition to the Electric LEAC filing spreadsheet and the items listed above, the Authority is providing the following supplemental exhibits:

- a. LEAC Workbook (Attachment A)
- b. MFR 1-6
- c. CME Group Daily Bulletin
- d. Line Loss / Streetlight Reports
- e. Monthly Financial Statements
- f. Cash Receipts Analysis
- g. Solar Invoices
- h. Electric and Water Billed Revenues

Water LEAC Charge Methodology

As summarized from Table B-2 of Attachment B, the components of the proposed Water LEAC are as follows:

	Historical	Historical	Current as Approved	Projected Proposed LEAC
	<i>2020 Historical</i>	<i>2021 Historical January - June</i>	<i>2021 July -December</i>	<i>2022 Calendar Year</i>
Summary of Costs - \$000s				
A Cost of Fuel	\$0	\$0	\$0	\$0
B Regulatory Expense (Docket 289 Costs)	10	0	0	10
C Total Current Fuel Costs	\$10	\$0	\$0	\$10
D Water Production Charge/RO (Net) [2]	\$7,764	\$4,319	\$3,928	\$8,427
E Electricity Charge for Purchased Water (Net) [3]	3,171	1,693	1,581	4,357
F Sub-total Current Purchased Water Costs	\$10,935	\$6,012	\$5,508	\$12,784
G Total Current Water Costs (Net)	\$10,945	\$6,012	\$5,508	\$12,794
H Base Rate Recovery	(3,311)	(1,406)	(1,687)	(3,442)
I Current LEAC Costs	\$7,635	\$4,606	\$3,821	\$9,352
Deferred Fuel Costs:				
J Amortized GO Note Principal & Interest	\$0	\$0	\$0	\$0
K Other Amortized Deferred Fuel Costs	(1,852)	(2,150)	(875)	2,392
L Sub-total Deferred Fuel Costs:	(\$1,852)	(\$2,150)	(\$875)	\$2,392
M Total Period Costs	\$5,782	\$2,456	\$2,946	\$11,743
Summary of Costs - \$per kGal				
Cost of Fuel	\$0.00	\$0.00	\$0.00	\$0.00
Regulatory Expense (Docket 289 Costs)	\$0.01	\$0.00	\$0.00	\$0.01
Total Current Fuel Costs	\$0.01	\$0.00	\$0.00	\$0.01
Water Production Charge/RO (Net) [2]	\$6.75	\$8.85	\$6.71	\$7.05
Electricity Charge for Purchased Water (Net) [3]	\$2.76	\$3.47	\$2.70	\$3.64
Sub-total Current Purchased Water Costs	\$9.51	\$12.31	\$9.40	\$10.70
Total Current Water Costs (Net)	\$9.52	\$12.31	\$9.40	\$10.70
Base Rate Recovery	(\$2.88)	(\$2.88)	(\$2.88)	(\$2.88)
Current LEAC Costs	\$6.64	\$9.43	\$6.52	\$7.82
Deferred Fuel Costs:				
Amortized GO Note Principal & Interest	\$0.00	\$0.00	\$0.00	\$0.00
Other Amortized Deferred Fuel Costs	(\$1.61)	(\$4.40)	(\$1.49)	\$2.00
Sub-total Deferred Fuel Costs:	(\$1.61)	(\$4.40)	(\$1.49)	\$2.00
Total Period Costs	\$5.03	\$5.03	\$5.03	\$9.82

The Authority is requesting a \$4.79/kGal increase in the current Water LEAC from \$5.03 to \$9.82 effective on all bills rendered as of January 1, 2022.

The amounts shown above are based upon an internal electric rate between the Water and Electric Systems based on the Fuel Cost component derived from the most recent annual (unaudited) financial statement (i.e., the most recent June Fuel expense (annual), plus: 1) a 3-cent allowance for O&M; and 2) a 1-cent allowance for A&G; The rate used for the proposed period is based on the projected semi-annual fuel cost for January - June 2022. The amount can be found on tab B-11 in Attachment B and also on tab A-6 in the ELEAC filing (Attachment A).

Water LEAC Differential Analysis

To provide the Public Services Commission with information in support of the proposed LEAC, a differential analysis has been prepared to illustrate the factors that account for the proposed change in the LEAC. A comparison of the proposed LEAC to the currently adopted LEAC is included as Table B-1 of Attachment B, and additional comparative analysis is shown on Table B-2.

The net effect of the proposed rate increase is reflected in the table below:

Line No.	Description	Monthly Bill Comparison			
		Existing Bill [1] Current LEAC	Existing Bill [2] Proposed LEAC	Increase (Decrease) in Bill- \$	Increase (Decrease) in Bill- %
<u>RESIDENTIAL</u>					
1	0 - 1,000 Monthly Gallons				
2	Above 1,000 Monthly Gallons				
4	Proposed Line Loss Reduction Capital Surcharge				
5	Monthly Bill Based on 2,400 Monthly Gallons	\$61.81	\$73.30	\$11.50	18.60%
6	Monthly Bill Based on 5,000 Monthly Gallons	\$131.46	\$155.41	\$23.95	18.22%
7	Monthly Bill Based on 7,500 Monthly Gallons	\$198.44	\$234.36	\$35.93	18.10%
8	Monthly Bill Based on 10,000 Monthly Gallons	\$265.41	\$313.31	\$47.90	18.05%
<u>COMMERCIAL</u>					
9	All Monthly Gallons				
10	Proposed Line Loss Reduction Capital Surcharge				
11	Monthly Bill Based on 25,000 Monthly Gallons	\$669.75	\$789.50	\$119.75	17.88%
<u>VI GOVERNMENT</u>					
12	All Monthly Gallons				
13	Proposed Line Loss Reduction Capital Surcharge				
14	Monthly Bill Based on 95,000 Monthly Gallons	\$2,545.05	\$3,000.10	\$455.05	17.88%

The Water LEAC rate proposed for the period would result in an increase in total monthly charges to the average Residential customer of \$11.50, which would be a increase of 18.60% in total charges to the customer.

Mr. Donald Cole
Public Services Commission
October 19, 2021
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Sincerely,

A handwritten signature in black ink, appearing to read "Shawn A. Hill". The signature is fluid and cursive, with a large initial "S" and "H".

Shawn A. Hill
Manager, Pricing, Rates and Strategic Planning