Memorandum

Date: December 23, 2021

To: San Diego Unified Port District

Prepared by: Burns & McDonnell Engineering Company and the Electric Power Research Institute

Subject: Assessment of Supportable Government Code Section 4217 Findings for the Tenth Avenue Marine Terminal Microgrid Project and Solar Photovoltaic Array

INTRODUCTION

Burns & McDonnell Engineering Company (BMCD) and Electric Power Resource Institute (EPRI) were tasked by San Diego Unified Port District (District) in September 2020 to assess the Tenth Avenue Marine Terminal Microgrid Infrastructure Project and solar photovoltaic (PV) array relative to Government Code Section 4217.10 et seq. Government Code Section 4217.12 requires that the anticipated cost savings to the District of electricity from the project be more than the anticipated marginal cost of constructing the project. The project includes a microgrid controller, battery energy storage system (BESS), and electrical infrastructure improvements combined with a solar PV array. The solar PV array portion of the project is to be procured through a power purchase agreement (PPA) and will be installed through that agreement while the BESS and supporting microgrid infrastructure will be paid for by the District using grant funds provided by the California Energy Commission (CEC). The solar PV array PPA annual costs will be paid by the District to the Seller of the PPA monthly over the 20-year term of the PPA. The BESS and supporting microgrid infrastructure project and its contractor, EDF, has already been budgeted by the District as a part of the District's utility expenses. This document outlines independent analyses completed by BMCD and EPRI for the microgrid project and proposed solar PV array PPA. The solar PV array PPA and microgrid project will be used together as a single system to generate annual savings for the District.

2. EXECUTIVE SUMMARY

The main findings from the evaluation are below.

2.1. General Findings

a. A review of the District's electric utility data confirmed that the microgrid's solar PV and BESS components were appropriately sized to the location's load shape and demand.

b. The project BESS and microgrid pricing from EDF Renewables, the microgrid contractor, is within the window of anticipated market pricing for this size and type of project.

c. BMCD understands that the District is preparing to execute a solar PPA that was selected in the recent Solar PPA Request for Proposals (RFP) solicitation process. The District has received formal proposals through the Solar PPA RFP and has selected a 20-year PPA with a price of $0.1090 per kWh.

2.2. Project Financial Modeling

a. Consistent with Government Code Section 4217.10 et seq. (Appendix 2), the anticipated cost savings analyses presented in this report leverages the System Advisor Model (SAM) and the Distributed Energy Resources-Value Estimation Tool (DER-VET) modeled by BMCD and EPRI respectively (see Table A-1 and A-2) to estimate the changes in marginal cost of electricity as a result of this project. The costs evaluated are specific to the time period the microgrid infrastructure project would operate (20 years) and the modeled electrical cost savings that would occur during this time as compared to the cost to construct the microgrid.

b. The project will result in an estimated nominal electricity bill savings to the District of $3,799,817 over 20 years. As presented in Table 1, this analysis assumes an average energy savings based on the results of the two models prepared. The estimated solar PPA cost savings are $2,118,467 over 20 years at a 2% discount rate and reduced SDG&E electricity bills to the District of $5,918,284 over 20 years. The microgrid project construction costs are $2,770,531. Combined project construction and solar PPA costs are projected to be less than the electric bill savings. Both models resulted in a positive net present value (NPV) with an average NPV of $1,029,286 at a 2% discount rate.

c. The CEC grant for the microgrid infrastructure of approximately $3,800,000 (of the $4,985,272 CEC full grant amount) covers the full capital cost of the project, and the remaining grant funds and District electricity cost savings are sufficient to cover the microgrid operations and maintenance costs during the grant funding period. Overall, this project will generate a net present value benefit of approximately $4 million over 20 years when factoring in the CEC grant funds.

d. This modeling effort included the following assumptions, which are further described in this report: nominal discount rate of 2%, real discount rate of 0%, and inflation rate of 2%. Financial modeling is based on hourly site usage, solar PV production, and BESS charging and discharging algorithms.

e. The financial model is sensitive to the assumed annual utility energy cost (July 2019 – July 2020) and escalation rate. BMCD and EPRI assumed an average SDG&E rate escalation above inflation of 4% for a combined rate of 6%.

f. To comply with Government Code Section 4217.10 et seq., this analysis is limited to changes in the marginal cost of electricity. A future analysis will include a full business case and a holistic assessment of the project.

Table 1: Project Financial Metrics Summary of BMCD and EPRI Analyses

Metric	BMCD Analysis	EPRI Analysis	Averages (where applicable)
PPA RATE, $/kWh, X% Escalator, Year 1	$0.1090; 0%	$0.1090; 0%	-
Annual Utility Rate Escalator*	6.0%	6.0%	-
Electric Bill Savings (Year 1)	$219,984	$211,768	$215,876
Existing SDG&E Utility Rate	AL-TOU Primary	AL-TOU Primary	-
Future SDG&E Utility Rate	AL-TOU Primary	DG-R Primary	-
Electric Bill Savings (2% discounted rate, 20 year)	$5,704,244	$6,132,323	$5,918,283
PPA Operating Costs (Year 1)**	-$135,593	-$135,596	-$135,595
PPA Operating Costs (2% discounted rate, 20 year)	- $2,115,003	- $2,121,931	-$2,118,467
Annual Net Savings (Year 1)	$84,391	$76,172	$80,282
Capital Investment	-$2,770,531	-$2,770,531	-$2,770,531
NPV (2.0% Nominal Discount Rate)	$818,711	$1,239,861	$1, 029,286

*Annual Utility Rate Escalator is 4% in the model on top of 2% inflation for a combined 6%. The District requested that BMCD & EPRI use a 6% escalator. SDG&E electric rates have increased 4% per year on average over the last 4 years. Source: Rate Trends 2009-2019

**BMCD assumed TAMT analysis would remain on AL-TOU primary rate. EPRI analysis assumed TAMT would switch from AL-TOU primary to DG-R primary rate.

***Minor differences in the PPA Operating Costs exist among the two analyses due to variations in modeling of the Solar PV and load profiles. This results in minor differences to the cost assumptions, primarily attributable to the degradation of equipment overtime.

2.3. Solar Power Purchase Agreement and Microgrid Contract

a. BMCD used the best and final pricing for the solar PPA selected in 2021 Solar RFP of $0.1090 per kWh. The dollars per kWh price of the Selected solar PPA is 12 percent higher than assumed in previous studies due to inflation and market pricing changes.
b. The District will own and retire all environmental attributes (i.e., Renewable Energy Certificates [RECs]), not the solar PPA provider, to ensure the District can claim the beneficial environmental credits for their environmental goals and/or obligations. RECs for similar projects have had little monetary value so the RECs should not impact the PPA price.
c. The solar PV array PPA selected by the District is estimated to provide energy production and capacity that is within an acceptable range with the assumptions developed in previous studies prepared by BMCD.
d. EDF provided performance ratings and warranties on key attributes for the BESS including round-trip efficiency, degradation, capacity output, and storage.
e. EDF provided a fixed fee proposal for the BESS and supporting microgrid infrastructure.

2.4. Project Production & Performance Modeling

a. BMCD modeled solar PV production and performance using National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) using weather data from the 92101 postal code in San Diego. The model has been updated from the previous Study such that the annual solar energy generated by the solar PV array is 1,244 MWh in Year 1. The solar generation is based on the estimates provided from the selected solar PPA contractor.
b. BMCD utilized load data at the site from July 2019-July 2020 to model future energy costs and savings from the BESS and solar PPA.
c. BMCD has an annual solar PV array degradation rate of 0.5%/year, which is a common value and aligns with the selected PPA provider's estimates.
d. The BESS modeled in the analysis was calibrated to the specifications proposed in EDF's proposal.
e. The round-trip efficiency of the BESS is modeled to be 87%.

3. BURNS & MCDONNELL PROJECT PERFORMANCE FINDINGS

3.1.System Sizing and Performance

The system was sized to offset at least 100% of the District's electricity usage at TAMT. Table 2 details the system size and expected year-1 production. System sizes are subject to minor modification during the final project design. The selected PPA provider is providing a 700 kW AC

solar array system that is estimated to provide 1,244 MWh per year with 1,152 MWh per year provided by the combined PV & BESS.

Table 2: PV System Sizing and Expected 1-Year Production

Configuration	System Size kW AC	Year-1 PV Production MWh	Year-1 PV & BESS Production MWh	Year-1 Site Load MWh	Usage offset Year 1, PV only	Usage offset Year 1, PV & BESS
Solar PV & BESS	700	1,244	1,152	1,100	113%	105%

3.2. Utility Tariff Analysis Results

BMCD conducted rate modeling using the SDG&E AL TOU primary rate with net billing using NREL's SAM software. Both the Solar PPA only and the Solar PPA + BESS configurations were modeled. Table 3 presents the modeling results of Year-1 savings, bill offset, and the value of the savings of the two configurations. The bill savings are projected to increase based on inflation while the PPA costs remain relatively flat.

Table 3: Utility Rate Analysis Results, Year 1

Configuration	Bill Savings ($/year)	PPA Cost ($/year)	Net Cash Flow ($/year)	Bill offset %	Value of Energy ($/kWh)
Solar PPA Only	$ 145,590	$ 135,593	$9,997	50%	$0.1170
Solar PPA & BESS	$ 219,984	$ 135,593	$ 84,391	75%	$0.1768

3.3. Life Cycle Modeling

BMCD prepared a 20-year financial model to determine the estimated financial performance of both Solar PPA on a standalone basis and the combined Solar PPA + BESS project. Combined project construction and solar PPA costs are projected to be less than the electric bill savings, resulting in an estimated NPV of $818,711(Table 4). The study assumed a 2% discount rate. A 20-year cash-flow analysis of the Solar PPA & BESS configuration is presented in in Table A-1 of Appendix 1.

Table 4: Lifecycle Savings Analysis Results

Configuration	Year – 1 Savings ($)*	20-Year NPV**
Solar PPA Only	$9,997	$1,878,644
Solar PPA & BESS	$84,391	$818,711

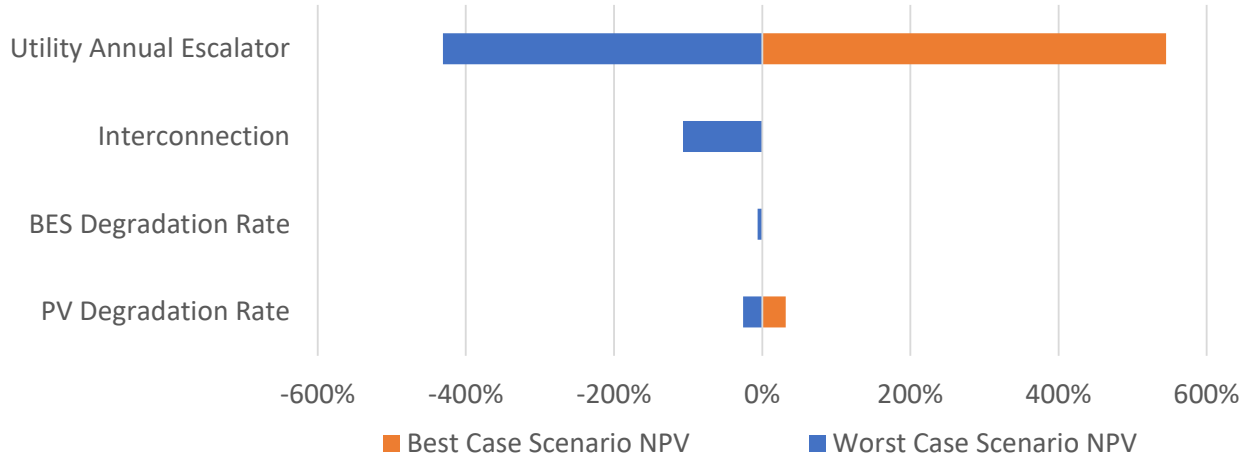
*This is the calculated as the difference between the annual bill savings (Year 1) and the annual solar PPA cost (Year 1). This doesn't include the BESS capital cost.

** This is calculated as the difference between the discounted total bill savings and the discounted total cost (both solar PPA and BESS capital cost) over the project lifetime (20 years).

3.4.Sensitivity and Risk Analysis

In the sensitivity and risk analysis, BMCD assessed the impacts of the key project variables. Figure 1 below shows the parameter sensitivity based on changing each variable by comparing the 20-Year NPV of that scenario to the base case NPV.

Figure 1: Sensitivity Analysis - % Change from the Base Case



The sensitivity analysis variables for each scenario are outlined in Table 5. Interconnection costs are difficult to assume at this time; however, the Tenth Avenue Marine Terminal is located adjacent to downtown San Diego on a robust network, has low solar PV penetration, and is a relatively small (<1,000 kilowatt [kW]) solar PV system. Therefore, interconnection costs are expected to

be a low percentage of the overall project budget. The degradation of the solar PV array and BESS were also considered at various annual rates to assess the overall impact to the NPV.

Table 5: Variables for Sensitivity Analysis

Variable	Set Value	Low Bound	High Bound
Annual Utility Rate Escalation (%/year)*	6%	4%	8%
PV Degradation Rate	0.5%	0.25%	0.75%
BES Degradation Rate	2.5%	1.5%	3.5%
Interconnection Cost	$0	$ 0	$ 200,000

*Annual utility rate escalation set value of 6% includes 2% inflation.

4. ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PROJECT PERFORMANCE FINDINGS

4.1. System Sizing and Performance

Table 6 details the system size and expected year-1 production based on the selected PPA proposal. The system size is subject to changes in the final project design.

Table 6: PV System Sizing and Expected 1-Year Production

Configuration	System Size kW AC	Year-1 Production MWh	Usage offset Year 1, PV & BESS MWh
PV & BESS	700	1,224	1,152

4.2. Utility Tariff Analysis Results

EPRI conducted modeling using the SDG&E AL TOU and DG-R rates with net billing using EPRI's DER-VET software. The Solar PPA only configuration and Solar PPA + BESS configuration were modeled. Table 7 shows the modeling of Year-1 savings, bill offset, and the value of the produced solar energy of the two configurations. The bill savings are projected to increase based on inflation while the PPA costs remain relatively flat.

Table 7: Utility Rate Analysis Results, Year 1

Configuration	Bill Savings ($/year)	PPA Cost ($/year)	Net Cash Flow ($/year)	Bill offset %	Value of Energy ($/kWh)
Solar PPA Only	$156,364	$135,596	$20,768	62%	$0.1257
Solar PPA & BESS	$211,768	$135,596	$76,172	84%	$0.1702

*Details provided as an appendix.

4.3. Life Cycle Modeling

EPRI performed a 20-year financial model to determine the estimated financial performance of both the Solar PPA only configuration and the Solar PPA + BESS project configuration. Table 8 below summarizes the key financial metrics from the proposal and BMCD's financial and DER-VET software production model. A 20-year cash-flow analysis is presented in Table A-2 of Appendix 1.

Table 8: Lifecycle Savings Analysis Results

Configuration	Year 1 Savings ($)*	20-Year NPV Savings**
Solar PPA Only	$20,768	$2,406,025
Solar PPA & BESS	$76,172	$1,239,861

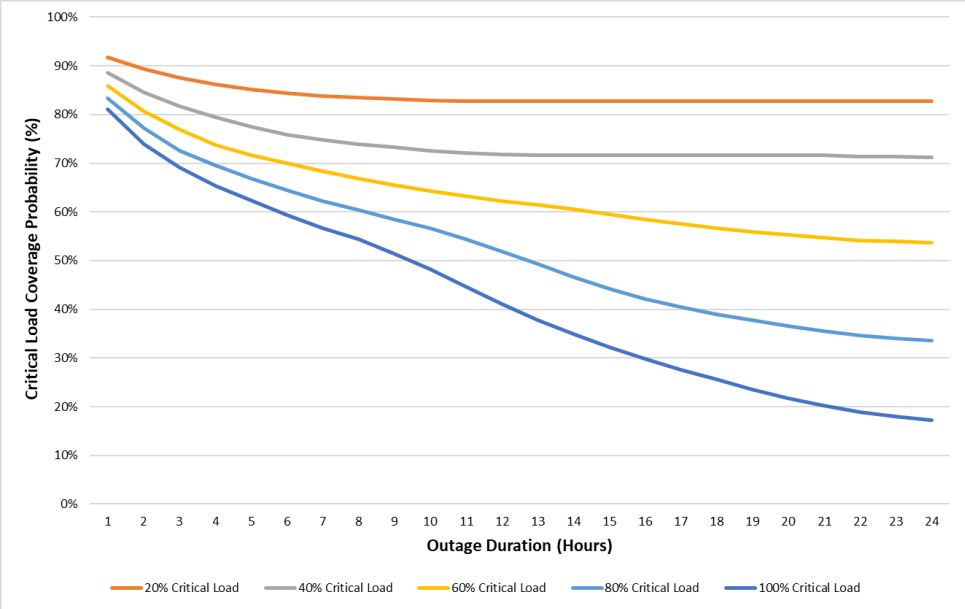
*This is the calculated as the difference between the annual bill savings (Year 1) and the annual solar PPA cost (Year 1). This doesn't include the BESS capital cost.

** This is calculated as the difference between the discounted total bill savings and the discounted total cost (both solar PPA and BESS capital cost) over the project lifetime (20 years).

4.4. Critical Load Coverage Probability Analysis

EPRI performed a critical load coverage probability analysis to model the probability of the BESS + Solar PV system to serve different percentages of the critical load for different durations of outage. The worst-case outage scenario analyzed is 24 hrs. Figure 2 presents the critical load served during an outage as a percentage of the total site load.

Figure 2 EPRI Critical Load Coverage Probability Analysis



5. KEY CONSIDERATIONS

5.1 Project Controls and Quality Control

It is important for the District to add project controls and technical specifications in the contracting and project demonstration phases to protect the District's interests from project construction through system operation.

a. Performance Guarantees/BESS savings

b. Interconnection and soft costs (can be negotiated into PPA)

5.2 Interconnection

Interconnecting systems greater than 1,000 kW include risk of utility side upgrades required by SDG&E which must be financed by the project. The interconnection process can also extend the project schedule, especially if SDG&E needs to complete a detailed interconnection study on the local SDG&E distribution system and the associated costs. Since this project is under 1,000 kW the risk of interconnection upgrades is not as great and will be determined in the interconnection

process. The District conducted a Rule 21 pre-application process and no additional costs/issues for interconnection were identified at the time with SDG&E.

6. PROJECT NEXT STEPS

a. Maintain awareness of BESS incentives (e.g., Self-Generation Incentive Program) Changes: Significant changes in BESS incentives could result in BESS systems providing improved financial benefits.
b. Commissioning – EDF will commission the microgrid infrastructure. A District representative will confirm the commissioning of the site, utility interconnection, and successful startup of the systems.
c. Project Close Out - Ensure that all contract requirements are met, and the project is closed and certified with permitting authorities.
d. Performance Management – Audit PV and BESS system performance monthly to ensure system performance, operations, and maintenance requirements are being met. Determine the realized utility savings annually.

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Appendix 1

Table 1-1. BMCD Cash Flow Analysis of Solar PPA and BESS Microgrid

Year	Energy | (MWh)	Electricity bill without system ($/yr)	Electricity bill with system ($/yr)	Electricity bill Savings from system ($/yr)	Solar PPA Expenses ($)	Project Capital Investment ($)	Net cash flow | ($)	Cummulative cash flow ($)
0	-	$ -	$ -	$ -	$ -	$ (2,770,530)	$ (2,770,530)	$ (2,770,530)
1	1,244	$ 290,442	$ 70,458	$ 219,984	$ (135,593)	$ -	$ 84,391	$ (2,686,139)
2	1,238	$ 307,869	$ 75,380	$ 232,489	$ (134,915)	$ -	$ 97,574	$ (2,588,564)
3	1,232	$ 326,341	$ 79,800	$ 246,541	$ (134,237)	$ -	$ 112,304	$ (2,476,260)
4	1,225	$ 345,921	$ 85,429	$ 260,492	$ (133,559)	$ -	$ 126,933	$ (2,349,326)
5	1,219	$ 366,677	$ 93,332	$ 273,345	$ (132,881)	$ -	$ 140,464	$ (2,208,862)
6	1,213	$ 388,677	$ 104,236	$ 284,441	$ (132,203)	$ -	$ 152,238	$ (2,056,624)
7	1,207	$ 411,998	$ 114,451	$ 297,547	$ (131,525)	$ -	$ 166,022	$ (1,890,601)
8	1,200	$ 436,718	$ 123,810	$ 312,908	$ (130,847)	$ -	$ 182,061	$ (1,708,540)
9	1,194	$ 462,921	$ 133,364	$ 329,557	$ (130,169)	$ -	$ 199,388	$ (1,509,152)
10	1,188	$ 490,696	$ 145,399	$ 345,297	$ (129,491)	$ -	$ 215,806	$ (1,293,346)
11	1,182	$ 520,138	$ 159,525	$ 360,613	$ (128,813)	$ -	$ 231,800	$ (1,061,546)
12	1,176	$ 551,346	$ 170,525	$ 380,821	$ (128,135)	$ -	$ 252,686	$ (808,860)
13	1,169	$ 584,427	$ 187,256	$ 397,171	$ (127,457)	$ -	$ 269,714	$ (539,146)
14	1,163	$ 619,493	$ 204,811	$ 414,682	$ (126,779)	$ -	$ 287,903	$ (251,243)
15	1,157	$ 656,662	$ 232,519	$ 424,143	$ (126,101)	$ -	$ 298,042	$ 46,799
16	1,151	$ 696,062	$ 250,169	$ 445,893	$ (125,423)	$ -	$ 320,470	$ 367,269
17	1,144	$ 737,826	$ 273,568	$ 464,258	$ (124,745)	$ -	$ 339,513	$ 706,782
18	1,138	$ 782,095	$ 301,449	$ 480,646	$ (124,067)	$ -	$ 356,579	$ 1,063,361
19	1,132	$ 829,021	$ 336,607	$ 492,414	$ (123,389)	$ -	$ 369,025	$ 1,432,386
20	1,070	$ 878,762	$ 359,849	$ 518,913	$ (116,625)	$ -	$ 402,288	$ 1,834,673
Total (Not Discounted)	23,642	$ 10,684,092	$ 3,501,937	$ 7,182,155	$ (2,576,952)	$ (2,770,530)	$ 1,834,673	N/A
Total (Discounted 2%)	N/A	$ 8,410,557	$ 2,706,314	$ 5,704,244	$ (2,115,003)	$ (2,770,530)	$ 818,711	N/A

Note: Net Cash Flow is equivalent to Electricity Bill Savings from System + Solar PPA Expenses + Project Capital Investment

Table 1-2 EPRI Cash Flow Analysis of Solar PPA and BESS Microgrid

Year	Energy | (kWh)	Electricity bill without system ($/yr)	Electricity bill with system ($/yr)	Electricity bill Savings from system ($/yr)	Solar PPA Expenses ($)	Project Capital Investment ($)	ES O&M ($)	Net cash flow | ($)	Cummulative cash flow | ($)
0	-	$ -	$ -	$ -	$ -	$ (2,770,530)		$ (2,770,530)	$ (2,770,530)
1	1,244,000	$ 250,099	$ 38,331	$ 211,768	$ (135,596)	$ -	$ -	$ 76,172	$ (2,694,358)
2	1,237,780	$ 265,105	$ 40,631	$ 224,474	$ (134,918)	$ -	$ -	$ 89,556	$ (2,604,802)
3	1,231,591	$ 281,011	$ 43,069	$ 237,942	$ (134,243)	$ -	$ -	$ 103,699	$ (2,501,103)
4	1,225,433	$ 297,872	$ 45,653	$ 252,219	$ (133,572)	$ -	$ -	$ 118,647	$ (2,382,456)
5	1,219,306	$ 315,744	$ 48,392	$ 267,352	$ (132,904)	$ -	$ -	$ 134,448	$ (2,248,009)
6	1,213,209	$ 334,689	$ 51,296	$ 283,393	$ (132,240)	$ -	$ -	$ 151,153	$ (2,096,855)
7	1,207,143	$ 354,770	$ 54,374	$ 300,397	$ (131,579)	$ -	$ -	$ 168,818	$ (1,928,037)
8	1,201,108	$ 376,057	$ 57,636	$ 318,421	$ (130,921)	$ -	$ -	$ 187,500	$ (1,740,537)
9	1,195,102	$ 398,620	$ 61,094	$ 337,526	$ (130,266)	$ -	$ -	$ 207,260	$ (1,533,278)
10	1,189,127	$ 422,537	$ 64,760	$ 357,777	$ (129,615)	$ -	$ -	$ 228,163	$ (1,305,115)
11	1,183,181	$ 447,889	$ 68,645	$ 379,244	$ (128,967)	$ -	$ -	$ 250,277	$ (1,054,838)
12	1,177,265	$ 474,763	$ 72,764	$ 401,999	$ (128,322)	$ -	$ -	$ 273,677	$ (781,161)
13	1,171,379	$ 503,249	$ 77,130	$ 426,119	$ (127,680)	$ -	$ -	$ 298,438	$ (482,723)
14	1,165,522	$ 533,443	$ 81,758	$ 451,686	$ (127,042)	$ -	$ -	$ 324,644	$ (158,079)
15	1,159,694	$ 565,450	$ 86,663	$ 478,787	$ (126,407)	$ -	$ -	$ 352,380	$ 194,301
16	1,153,896	$ 599,377	$ 91,863	$ 507,514	$ (125,775)	$ -	$ -	$ 381,739	$ 576,041
17	1,148,126	$ 635,340	$ 97,375	$ 537,965	$ (125,146)	$ -	$ -	$ 412,819	$ 988,860
18	1,142,386	$ 673,460	$ 103,217	$ 570,243	$ (124,520)	$ -	$ -	$ 445,723	$ 1,434,583
19	1,136,674	$ 713,868	$ 109,410	$ 604,457	$ (123,897)	$ -	$ -	$ 480,560	$ 1,915,143
20	1,130,990	$ 756,700	$ 115,975	$ 640,725	$ (123,278)	$ -	$ -	$ 517,447	$ 2,432,589
Total (Not Discounted)	23,732,913	$ 9,200,044	$ 1,410,037	$ 7,790,007	$ (2,586,887)	$ (2,770,530)	$ -	$ 2,432,589	N/A
Total (Discounted 2%)	N/A	$ 7,242,309	$ 1,109,986	$ 6,132,323	$ (2,121,931)	$ (2,770,530)	$ -	$ 1,239,861	N/A

Note: Net Cash Flow is equivalent to Electricity Bill Savings from System + Solar PPA Expenses + Project Capital Investment

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Table 1-3 AL-TOU Primary Rate Schedule as of 12-14-2021

SDG&E AL-TOU Rate Schedule			
	Summer		
	On Peak	Off Peak	Super Off Peak
Energy Charge ($/kWh)	$ 0.19102	$ 0.12189	$ 0.1026
Max Peak ($/kW)	$ 35.04	$ -	$ -
Non-coincident Peak ($/kW)	$ 26.55	$ 26.55	$ 26.55
	Winter		
Energy Charge ($/kWh)	$ 0.20235	$ 0.11866	$ 0.09436
Max Peak ($/kW)	$ 23.01	$ -	$ -
Non-coincident Peak ($/kW)	$ 26.55	$ 26.55	$ 26.55

[1] https://www.sdge.com/sites/default/files/regulatory/11-1-21%20Med%20Large%20Commercial%20Total%20Rates%20Table_1.pdf

Table 1-4 BMCD System Advisor Model Assumptions

Assumptions	
Inflation Rate	2.0%/year
Real Discount Rate	0.0%/year
Nominal Discount Rate	2.0%/year
Total Utility Escalation Rate*	6.0%/year

*Total utility escalation rate includes 2% inflation

Table 1-5 DG-R Rate Schedule as of 12-14-2021

SDG&E DG-R Rate Schedule			
	Summer		
	On Peak	Off Peak	Super Off Peak
Energy Charge ($/kWh)	$ 0.66585	$ 0.18877	$ 0.10958
Max Peak ($/kW)	$ 3.52	$ -	$ -
Non-coincident Peak ($/kW)	$ 16.92	$ 16.92	$ 16.92
	Winter		
Energy Charge ($/kWh)	$ 0.42429	$ 0.12140	$ 0.1284
Max Peak ($/kW)	$ 0.73	$ -	$ -
Non-coincident Peak ($/kW)	$ 16.92	$ 16.92	$ 16.92

[1] https://www.sdge.com/sites/default/files/regulatory/11-1-21%20Med%20Large%20Commercial%20Total%20Rates%20Table_1.pdf

Table 1-6 EPRI DER-VET Modeling Assumptions

Assumptions	
Inflation Rate	2.0%/year
Real Discount Rate	0.0%/year
Nominal Discount Rate	2.0%/year
Total Utility Escalation Rate*	6.0%/year

*Total utility escalation rate includes 2% inflation

Appendix 2

State of California Government Code Section 4217.10 et seq.

GOVERNMENT CODE - GOV
TITLE 1. GENERAL [100 - 7914] (Title 1 enacted by Stats. 1943, Ch. 134.)
DIVISION 5. PUBLIC WORK AND PUBLIC PURCHASES [4000 - 4563] (Division 5 enacted by Stats. 1943, Ch. 134.)

CHAPTER 3.2. Energy Conservation Contracts [4217.10 - 4217.18] (Chapter 3.2 added by Stats. 1983, Ch. 868, Sec. 1.)

4217.10. To help implement the policy set forth in Section 25008 of the Public Resources Code, and to extend that policy to facilities of local governments, public agencies may develop energy conservation, cogeneration, and alternate energy supply sources at the facilities of public agencies in accordance with this chapter.
(Added by Stats. 1983, Ch. 868, Sec. 1.)

4217.11. The following terms, whenever used in this chapter, have the meanings given in this section, except where the context clearly indicates otherwise:

(a) "Alternate energy equipment" means equipment for the production or conversion of energy from alternate sources as its primary fuel source, such as solar, biomass, wind, geothermal, hydroelectricity under 30 megawatts, remote natural gas of less than one billion cubic feet estimated reserves per mile from an existing gas gathering line, natural gas containing 850 or fewer British Thermal Units per standard cubic foot, or any other source of energy, the efficient use of which will reduce the use of fossil or nuclear fuels.

(b) "Cogeneration equipment" means equipment for cogeneration, as defined in Section 216.6 of the Public Utilities Code.

(c) "Conservation measures" means equipment, maintenance, load management techniques and equipment, or other measures to reduce energy use or make for a more efficient use of energy.

(d) "Conservation services" means the electrical, thermal, or other energy savings resulting from conservation measures, which shall be treated as a supply of such energy.

(e) "Energy conservation facility" means alternate energy equipment, cogeneration equipment, or conservation measures located in public buildings or on land owned by public agencies.

(f) "Energy service contract" means a contract entered into by a public agency with any person, pursuant to which the person will provide electrical or thermal energy or conservation services to a public agency from an energy conservation facility.

(g) "Facility financing contract" means a contract entered into by a public agency with any person whereby the person provides financing for an energy conservation facility in exchange for repayment of the financing and all costs and expenses related thereto by the public agency. A facility financing contract may provide for the person with whom the public agency contracts to provide any combination of feasibility studies for, and design and construction of, all or part of the energy conservation facility in addition to the financing and other related services, and may provide for an installment sale purchase, another form of purchase, or amortized lease of the energy conservation facility by the public agency.

(h) "Facility ground lease" means a lease of all, or any portion of, land or a public building owned by, or under lease to, a public agency to a person in conjunction with an energy service contract or a facility financing contract. A facility ground lease may include, in addition to the land on which energy conservation facilities will be located, easements, rights-of-way, licenses, and rights of access, for the construction, use, or ownership by the person of the facility and all related utility lines not owned or controlled by the interconnecting utility, and offsite improvements related thereto. A facility ground lease may also include the addition or improvement of utility lines and equipment

owned by the interconnecting utility which are necessary to permit interconnection between that utility and an energy conservation facility.

(i) "Person" means, but is not limited to, any individual, company, corporation, partnership, limited liability company, public agency, association, proprietorship, trust, joint venture, or other entity or group of entities.

(j) "Public agency" means the state, a county, city and county, city, district, community college district, school district, joint powers authority or other entity designated or created by a political subdivision relating to energy development projects, and any other political subdivision or public corporation in the state.

(k) "Public building" includes any structure, building, facility, or work which a public agency is authorized to construct or use, and automobile parking lots, landscaping, and other facilities, including furnishings and equipment, incidental to the use of any structure, building, facility, or work, and also includes the site thereof, and any easements, rights-of-way appurtenant thereto, or necessary for its full use.
(Amended by Stats. 2006, Ch. 198, Sec. 2. Effective January 1, 2007.)

4217.12. (a) Notwithstanding any other provision of law, a public agency may enter into an energy service contract and any necessarily related facility ground lease on terms that its governing body determines are in the best interests of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least two weeks in advance, and if the governing body finds:

(1) That the anticipated cost to the public agency for thermal or electrical energy or conservation services provided by the energy conservation facility under the contract will be less than the anticipated marginal cost to the public agency of thermal, electrical, or other energy that would have been consumed by the public agency in the absence of those purchases.

(2) That the difference, if any, between the fair rental value for the real property subject to the facility ground lease and the agreed rent, is anticipated to be offset by below-market energy purchases or other benefits provided under the energy service contract.

(b) State agency heads may make these findings without holding a public hearing.
(Amended by Stats. 1998, Ch. 328, Sec. 7. Effective August 21, 1998.)

4217.13. Notwithstanding any other provision of law, a public agency may enter into a facility financing contract and a facility ground lease on terms that its governing body determines are in the best interest of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least two weeks in advance, and if the governing body finds that funds for the repayment of the financing or the cost of design, construction, and operation of the energy conservation facility, or both, as required by the contract, are projected to be available from revenues resulting from sales of electricity or thermal energy from the facility or from funding that otherwise would have been used for purchase of electrical, thermal, or other energy required by the public agency in the absence of the energy conservation facility, or both. State agency heads may make these findings without holding a public hearing.
(Amended by Stats. 1998, Ch. 328, Sec. 8. Effective August 21, 1998.)

4217.14. Notwithstanding any other provision of law, the public agency may enter into contracts for the sale of electricity, electrical generating capacity, or thermal energy produced by the energy conservation facility at such rates and on such terms as are approved by its governing body. Any such contract may provide for a commitment of firm electrical capacity.
(Added by Stats. 1983, Ch. 868, Sec. 1.)

4217.15. The public agency may, but is not required to, base the findings required under Sections 4217.12 and 4217.13 on projections for electrical and thermal energy rates from the following sources:

(a) The public utility which provides thermal or electrical energy to the public agency.

(b) The Public Utilities Commission.

(c) The State Energy Resources Conservation and Development Commission.

(d) The projections used by the Department of General Services for evaluating the feasibility of energy conservation facilities at state facilities located within the same public utility service area as the public agency.
(Added by Stats. 1983, Ch. 868, Sec. 1.)

4217.16. Prior to awarding or entering into an agreement or lease, the public agency may request proposals from qualified persons. After evaluating the proposals, the public agency may award the contract on the basis of the experience of the contractor, the type of technology employed by the contractor, the cost to the local agency, and any other relevant considerations. The public agency may utilize the pool of qualified energy service companies established pursuant to Section 388 of the Public Utilities Code and the procedures contained in that section in awarding the contract.
(Amended by Stats. 1998, Ch. 328, Sec. 9. Effective August 21, 1998.)

4217.17. This chapter does not limit the authority of any public agency to construct energy conservation projects or to enter into other leases or contracts relating to the financing construction, operation, or use of alternate energy type facilities in any manner authorized under existing law. This chapter shall not be construed to abrogate Section 14671.6.
(Amended by Stats. 1998, Ch. 328, Sec. 10. Effective August 21, 1998.)

4217.18. The provisions of this chapter shall be construed to provide the greatest possible flexibility to public agencies in structuring agreements entered into hereunder so that economic benefits may be maximized and financing and other costs associated with the design and construction of alternate energy projects may be minimized. To this end, public agencies and the entities with whom they contract under this chapter should have great latitude in characterizing components of energy conservation facilities as personal or real property and in granting security interests in leasehold interests and components of the alternate energy facilities to project lenders.
(Added by Stats. 1983, Ch. 868, Sec. 1.)