Docket No. 20200176-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 17-18, 2020

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
DUKE ENERGY FLORIDA, LLC – DIRECT					
2	Benjamin M. H. Borsch	BMHB-1	Load Forecast	1	
3	Benjamin M. H. Borsch	BMHB-2	Fuel Forecasts	1	
4	Benjamin M. H. Borsch	BMHB-3	Cost Effectiveness (CPVRR) Analysis Results	1	
5	Benjamin M. H. Borsch	BMHB-4	Resource Plans	1	
6	Benjamin M. H. Borsch	BMHB-5	Cumulative Present Value Revenue Requirements. (CPVRR)	1	
7	Benjamin M. H. Borsch	BMHB-7	Clean and Legislative Versions of Tariff sheets 6.101, 6.405, 6.406, and 6.407.	1	Not Entered
8	Thomas G. Foster	TGF-1	Summary of CEC Program Revenue Requirements, Subscription Fees, and Bill Credits.	1	
9	Lon Huber	LH-1	Clean and Legislative Versions of Tariff sheets 6.101, 6.405, 6.406, and 6.407	1	

WALMART INC. – DIRECT					
10	Steve W. Chriss	SWC-1	Witness Qualifications Statement	1	
11	Steve W. Chriss	SWC-2	Stipulation (July 20, 2020, filed in connection with Storm Protection Plan Dockets)	1	
LEAGUE OF UNITED LATIN AMERICAN CITIZENS OF FLORIDA A/K/A LULAC FLORIDA EDUCATIONAL FUND, INC. – DIRECT					
12	Karl Rábago	KRR-1	Karl Rábago Resume		
13	Karl Rábago	KRR-2	Karl Rábago Prior Testimony		
14	Karl Rábago	KRR-3	SolarTogether CPVRR Summary	1-7	
15	Karl Rábago	KRR-4	FPL/Gulf Power Ten Year Site Plan Excerpts	1-7	
16	Karl Rábago	KRR-5	Duke Energy Florida, LLC Ten Year Site Plan	1-7	
DUKE ENERGY FLORIDA, LLC – REBUTTAL					
17	Lon Huber	LH-2	IREC Community Solar Checklist	1	
STAFF HEARING EXHIBITS					
18	Huber (1) Foster (2-3)		DEF’s Response to Staff’s First Set of Interrogatories, No. 1-3. *[Bates Nos. 00001-00006]*	1	
19	Foster		DEF’s Response to Staff’s First Production of Documents, No. 1. **Confidential DN. 11723-2020** *[Bates Nos. 00007-00008]*	1	

20	Huber (4, 5, 6(b), 18, 20 – 26) Stout (7, 8a, 17 [a – e]) Borsch (9 – 11, 15, 16, 17(f), 19) Foster (6(a), 8(b-d), 12 – 14)		DEF's Response to Staff's Second Set of Interrogatories, Nos. 4 – 26. Including attachments for responses 6, 10 – 14. **8(a) & 10 (b) – Confidential DN. 11610-2020** *[Bates Nos. 00009-00062]*	1	
21	Borsch		DEF's Response to Staff's Second Production of Documents, No. 4. *[Bates Nos. 00063-00065]*	1	
22	Borsch		DEF's Response to Staff's Amended Third Set of Interrogatories, Nos. 27-29. *[Bates Nos. 00066-00075]*	1	
23	Huber (1) Foster (8)		DEF's Corrected Response to LULAC's First Set of Interrogatories, No. 1, 8. *[Bates Nos. 00076-00082]*	1	
24	Foster		DEF's Corrected Response to LULAC's First Production of Documents, No. 1. **Confidential DN. 11723-2020** *[Bates Nos. 00083-00092]*	1	

25	Huber		DEF's Response to LULAC's Second Set of Interrogatories, Nos. 9, 14. *[Bates Nos. 00093-00099]*	1	
			HEARING EXHIBITS		
Exhibit Number	**Witness**	**Party**	**Description**		**Moved In/Due Date of Late Filed**
26	Huber	LULAC	LULAC-13 – DEFs Late filed exhibit from LULACs Oct. 26 Deposition		
27	Huber	LULAC	LULAC-15 – DEFs CORRECTED Response to LULACs 1st ROGs (1-8)		
28	Foster	LULAC	LULAC-27 – CEC - LULAC ROG 17 POD 14 - REDACTED from DEFs Response to LULAC 2 ROG (9-25)		
29	Foster	LULAC	LULAC-61 – DEF Resp to LULAC 1 ROG - CEC 749MW Model Case - Settlement (Filing)		
30	Chriss	LULAC	LULAC-45 – Walmart Responses and Objections to LULAC Interrogatories - Set 1 (PUBLIC)		
31	Borsch	LULAC	LULAC-62 – DEF Resp to LULAC ROG 2020-05 CEC_750MWs CPVRR_Results_05282020		
32	Borsch	LULAC	LULAC-19 – CEC AFUDC WACC Calc Support from DEFs CORRECTED Response to LULACs 1 POD (1-8)		

Duke Energy Florida
Witness: Benjamin Borsch
Exhibit No. ___(BMHB-1)

Load Forecast			
Year	Summer Firm Peak MW	Winter Firm Peak MW	Net Energy for Load Mwh
2020	8,915	9,406	43,644,906
2021	8,946	8,789	43,939,025
2022	9,007	9,167	44,591,037
2023	8,735	8,922	44,535,781
2024	8,769	9,012	44,880,342
2025	8,588	8,777	44,720,775
2026	8,612	8,880	44,954,812
2027	8,666	8,941	45,267,934
2028	8,759	9,003	45,777,936
2029	8,829	9,038	46,123,759
2030	8,904	9,091	46,525,804
2031	8,940	9,036	45,949,137
2032	9,031	9,222	46,468,945
2033	9,102	9,249	46,838,648
2034	9,191	9,316	47,322,026
2035	9,283	9,379	47,807,095
2036	8,984	9,075	48,371,288
2037	9,067	9,109	48,795,901
2038	9,158	9,173	49,285,725
2039	9,294	9,236	49,776,860
2040	9,405	9,338	50,380,732
2041	9,494	9,358	50,821,460
2042	9,570	9,336	51,310,772
2043	9,679	9,491	51,855,627
2044	9,985	9,594	52,453,876
2045	9,881	9,606	52,813,645
2046	9,985	9,673	53,311,439

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 2
PARTY: BMHB-1
DESCRIPTION: Load Forecast

Duke Energy Florida
Witness: Benjamin Borsch
Exhibit No. ___(BMHB-2)
Page 1 of 1

Fuel Forecasts

Fuel Mid Price Forecast (2020 TYSP)				Fuel High Price Forecast (2020 TYSP)				Fuel Low Price Forecast (2020 TYSP)			
Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil	Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil	Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil
	$/MMBTU				$/MMBTU				$/MMBTU		
2020	2.41	2.12	14.13	**2020**	2.41	2.12	14.13	**2020**	2.41	2.12	14.13
2021	2.45	2.18	13.89	**2021**	2.48	2.18	13.89	**2021**	2.45	2.18	13.89
2022	2.52	2.26	14.14	**2022**	2.76	2.26	14.14	**2022**	2.52	2.26	14.14
2023	2.60	2.43	14.32	**2023**	3.21	2.43	14.32	**2023**	2.60	2.43	14.32
2024	2.75	2.52	14.60	**2024**	3.79	2.53	14.60	**2024**	2.70	2.52	14.60
2025	2.99	2.72	14.96	**2025**	4.15	2.75	14.96	**2025**	2.86	2.71	14.96
2026	3.28	2.88	15.53	**2026**	4.58	2.93	15.53	**2026**	3.07	2.85	15.53
2027	3.68	3.09	16.18	**2027**	5.03	3.16	16.18	**2027**	3.38	3.05	16.18
2028	4.20	3.33	16.93	**2028**	5.60	3.40	16.93	**2028**	3.70	3.28	16.93
2029	4.58	3.44	17.62	**2029**	6.05	3.51	17.62	**2029**	3.98	3.38	17.62
2030	4.80	3.55	18.06	**2030**	6.34	3.65	18.06	**2030**	4.13	3.51	18.06
2031	5.08	3.96	18.46	**2031**	6.80	4.04	18.46	**2031**	4.40	3.91	18.46
2032	5.37	4.11	18.88	**2032**	7.14	4.18	18.88	**2032**	4.54	4.04	18.88
2033	5.34	4.25	19.31	**2033**	7.09	4.33	19.31	**2033**	4.51	4.18	19.31
2034	5.57	4.37	19.75	**2034**	7.54	4.47	19.75	**2034**	4.66	4.33	19.75
2035	5.78	4.43	20.20	**2035**	7.89	4.51	20.20	**2035**	4.83	4.37	20.20
2036	5.86	4.53	20.66	**2036**	7.99	4.61	20.66	**2036**	4.82	4.45	20.66
2037	6.26	4.67	21.14	**2037**	8.64	4.77	21.14	**2037**	5.13	4.59	21.14
2038	6.56	4.80	21.54	**2038**	9.15	4.91	21.54	**2038**	5.36	4.71	21.54
2039	6.68	4.96	21.93	**2039**	9.28	5.09	21.93	**2039**	5.44	4.86	21.93
2040	6.97	5.10	22.07	**2040**	9.85	5.26	22.07	**2040**	5.60	5.01	22.07
2041	7.21	5.24	22.64	**2041**	10.29	5.42	22.64	**2041**	5.80	5.18	22.64
2042	7.47	5.39	23.22	**2042**	10.74	5.58	23.22	**2042**	5.97	5.35	23.22
2043	7.65	5.53	23.42	**2043**	11.14	5.75	23.42	**2043**	6.04	5.51	23.42
2044	7.95	5.67	24.02	**2044**	11.33	5.92	24.02	**2044**	6.25	5.64	24.02
2045	8.39	5.82	24.22	**2045**	11.95	6.04	24.22	**2045**	6.54	5.75	24.22
2046	8.71	5.96	24.83	**2046**	12.57	6.21	24.83	**2046**	6.76	5.91	24.83
2047	8.85	6.10	25.45	**2047**	13.04	6.40	25.45	**2047**	6.85	6.03	25.45
2048	9.14	6.25	25.64	**2048**	13.55	6.56	25.64	**2048**	6.96	6.13	25.64
2049	9.36	6.39	26.28	**2049**	13.90	6.72	26.28	**2049**	7.01	6.25	26.28
2050	9.45	6.53	26.29	**2050**	14.22	6.88	26.29	**2050**	7.05	6.39	26.29
2051	9.69	6.69	26.95	**2051**	14.57	7.06	26.95	**2051**	7.23	6.55	26.95
2052	9.93	6.86	27.62	**2052**	14.94	7.23	27.62	**2052**	7.41	6.71	27.62
2053	10.18	7.03	28.31	**2053**	15.31	7.41	28.31	**2053**	7.60	6.88	28.31

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 3
PARTY: BMHB-2
DESCRIPTION: Fuel Forecasts

Cost Effectiveness (CPVRR) Analysis Results			
CPVRR Through Year 2053 2020$M	**Clean Energy Connection Solar - No CEC Solar**		
	Low Fuel Prices	**Mid Fuel Prices**	**High Fuel Prices**
2022 Clean Energy Connection Units	259	259	259
2023 Clean Energy Connection Units	454	454	454
2024 Clean Energy Connection Units	427	427	427
Conventional Generation	(353)	(353)	(353)
Fuel Cost	(702)	(827)	(1,113)
Variable Costs	(67)	(65)	(64)
Environmental Costs without Carbon	(0)	(1)	(3)
Program Administrative Costs	7	7	7
Total Solar Savings before CO2 Costs	**25**	**(99)**	**(385)**
CO2 Cost	(429)	(434)	(446)
Solar Project CPVRR (Savings)	**(404)**	**(533)**	**(831)**

Duke Energy Florida
Witness: Benjamin Borsch
Exhibit No. ___(BMHB-4)

Resource Plans

Year	No Clean Energy Connection Solar	Clean Energy Connection Solar
2020		
2021		
2022		Clean Energy Connection Solar 149.8 MW
2023		Clean Energy Connection Solar 299.6 MW
2024		Clean Energy Connection Solar 299.6 MW
2025		
2026		
2027	Combustion Turbine 451.6 MW	Combustion Turbine 225.8 MW
2028	Combustion Turbine 225.8 MW	
2029		Combustion Turbine 225.8 MW
2030	Combustion Turbine 225.8 MW	
2031		Combustion Turbine 225.8 MW
2032	Combustion Turbine 225.8 MW	
2033		Combustion Turbine 225.8 MW
2034	Combustion Turbine 903.2 MW	Combustion Turbine 677.4 MW
	Combined Cycle 1277.1 MW	Combined Cycle 1277.1 MW
2035		
2036		Combustion Turbine 225.8 MW
2037		
2038	Combustion Turbine 677.4 MW	Combustion Turbine 451.6 MW
2039		
2040	Combustion Turbine 225.8 MW	Combustion Turbine 225.8 MW
2041		
2042	Combined Cycle 1277.1 MW	Combined Cycle 1277.1 MW
2043		
2044	Combustion Turbine 451.6 MW	Combustion Turbine 451.6 MW
2045	Combustion Turbine 225.8 MW	Combustion Turbine 225.8 MW
2046		Combustion Turbine 225.8 MW

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 5
PARTY: BMHB-4
DESCRIPTION: Resource Plans

Duke Energy Florida
Witness: Benjamin Borsch
Exhibit No. ___(BMHB-5)
Page 1 of 1

Cumulative Present Value Revenue Requirements (CPVRR)		
		CPVRR $M 2020
	Program Admin. Costs	$ 7.3
Solar Revenue Requirements	Generation Capital ($M)	$ 937.7
	Transmission Interconnection ($M)	$ 108.8
	Fixed O&M ($M)	$ 93.8
Avoided Non Solar Fixed Costs	Generation Capital ($M)	$ (158.7)
	Transmission Interconnection ($M)	$ (28.9)
	Fixed O&M ($M)	$ (12.0)
	Gas Reservation Charges ($M)	$ (153.9)
Avoided System Costs	System Net Fuel ($M)	$ (826.9)
	Start Up and VOM ($M)	$ (64.6)
	Emissions ($M)	$ (435.5)
	Total CPVRR ($M)	**$ (532.7)**

EXHIBIT NOT ENTERED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 7
PARTY: BMHB-7
DESCRIPTION: Clean and Legislative Versions of Tariff sheets 6.101, 6.405, 6.406, and 6.407.

Exhibit No. __ (TGF-1)

Summary of CEC Program Revenue Requirements, Subscription Fees, and Bill Credits

($ millions)		CPVRR	Nominal Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033-2053
Discount Factor				0.94	0.88	0.82	0.77	0.72	0.68	0.64	0.60	0.56	0.52	0.49	0.46	
Fixed Revenue Requirements																
CEC Capital, O&M		$ 1,140.3	$ 2,728.3	$ -	$ 30.9	$ 87.1	$ 138.3	$ 131.3	$ 125.3	$ 112.4	$ 108.6	$ 105.5	$ 102.9	$ 100.5	$ 98.2	$ 1,587.4
Program Administrative Costs		$ 7.3	$ 16.8	$ 1.0	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.5	$ 0.6	$ 0.5	$ 0.5	$ 0.6	$ 0.4	$ 0.4	$ 9.6
Total DEF CEC Costs		$ 1,147.6	$ 2,745.1	$ 1.0	$ 31.5	$ 87.8	$ 139.0	$ 132.0	$ 125.8	$ 112.9	$ 109.1	$ 106.0	$ 103.5	$ 100.9	$ 98.5	$ 1,597.1
System Benefits (1)		$ (353.5)	$ (1,187.9)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.0)	$ (29.5)	$ (25.3)	$ (28.0)	$ (23.7)	$ (26.6)	$ (1,043.8)
Total Fixed Revenue Requirements (fav) unfav		**$ 794.2**	**$ 1,557.2**	**$ 1.0**	**$ 31.5**	**$ 87.8**	**$ 139.0**	**$ 132.0**	**$ 125.8**	**$ 102.0**	**$ 79.5**	**$ 80.8**	**$ 75.5**	**$ 77.2**	**$ 71.9**	**$ 553.3**
Variable Revenue Requirements																
System Net Fuel		$ (826.9)	$ (2,648.0)	$ -	$ (8.3)	$ (24.2)	$ (48.4)	$ (48.7)	$ (51.7)	$ (57.0)	$ (57.1)	$ (67.1)	$ (62.4)	$ (73.3)	$ (71.6)	$ (2,078.1)
Variable O&M		$ (64.6)	$ (178.0)	$ -	$ (1.4)	$ (3.8)	$ (5.3)	$ (4.4)	$ (4.6)	$ (5.1)	$ (6.1)	$ (5.2)	$ (5.8)	$ (6.7)	$ (6.4)	$ (123.1)
Emissions		$ (435.5)	$ (1,884.1)	$ -	$ (0.1)	$ (0.1)	$ (0.3)	$ (5.0)	$ (8.4)	$ (11.4)	$ (14.3)	$ (20.0)	$ (18.4)	$ (22.4)	$ (24.6)	$ (1,759.2)
Total Variable Revenue Requirements (fav) unfav		**$ (1,326.9)**	**$ (4,710.1)**	**$ -**	**$ (9.8)**	**$ (28.1)**	**$ (54.0)**	**$ (58.1)**	**$ (64.8)**	**$ (73.5)**	**$ (77.5)**	**$ (92.4)**	**$ (86.6)**	**$ (102.3)**	**$ (102.6)**	**$ (3,960.5)**
Net Revenue Requirements (fav) unfav		**$ (532.7)**	**$ (3,152.9)**	**$ 1.0**	**$ 21.7**	**$ 59.6**	**$ 85.0**	**$ 73.9**	**$ 61.1**	**$ 28.5**	**$ 2.1**	**$ (11.6)**	**$ (11.2)**	**$ (25.1)**	**$ (30.6)**	**$ (3,407.2)**
Participant Subscription Fees and Bill Credits	% of Total															
Subscription Fees (Revenue)		$ (833.4)	$ (2,251.5)	$ -	$ (15.0)	$ (45.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (1,516.0)
Bill Credits		$ 901.0	$ 2,542.1	$ -	$ 14.9	$ 44.6	$ 74.3	$ 74.8	$ 75.6	$ 76.3	$ 77.2	$ 77.7	$ 78.5	$ 79.2	$ 80.1	$ 1,789.0
Participant Net Distribution (Payment)	12.7%	**$ 67.6**	**$ 290.6**	**$ -**	**$ (0.1)**	**$ (0.5)**	**$ (0.8)**	**$ (0.2)**	**$ 0.5**	**$ 1.2**	**$ 2.1**	**$ 2.7**	**$ 3.4**	**$ 4.2**	**$ 5.1**	**$ 273.0**
General Body of Customers Revenue Requirement																
Fixed	% of Total															
Total Fixed Revenue Requirements		$ 794.2	$ 1,557.2	$ 1.0	$ 31.5	$ 87.8	$ 139.0	$ 132.0	$ 125.8	$ 102.0	$ 79.5	$ 80.8	$ 75.5	$ 77.2	$ 71.9	$ 553.3
Participant Subscription Fees (Revenue)	104.9%	$ (833.4)	$ (2,251.5)	$ -	$ (15.0)	$ (45.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (1,516.0)
Net Fixed Revenue Requirements (fav) unfav	-4.9%	**$ (39.2)**	**$ (694.3)**	**$ 1.0**	**$ 16.5**	**$ 42.7**	**$ 63.9**	**$ 56.9**	**$ 50.8**	**$ 26.9**	**$ 4.5**	**$ 5.7**	**$ 0.4**	**$ 2.1**	**$ (3.1)**	**$ (962.7)**
Variable	% of Total															
Total Variable Revenue Requirements (fav) unfav		$ (1,326.9)	$ (4,710.1)	$ -	$ (9.8)	$ (28.1)	$ (54.0)	$ (58.1)	$ (64.8)	$ (73.5)	$ (77.5)	$ (92.4)	$ (86.6)	$ (102.3)	$ (102.6)	$ (3,960.5)
Participant Bill Credits	67.9%	$ 901.0	$ 2,542.1	$ -	$ 14.9	$ 44.6	$ 74.3	$ 74.8	$ 75.6	$ 76.3	$ 77.2	$ 77.7	$ 78.5	$ 79.2	$ 80.1	$ 1,789.0
Net Variable Revenue Requirements (fav) unfav	32.1%	**$ (425.9)**	**$ (2,168.0)**	**$ -**	**$ 5.1**	**$ 16.4**	**$ 20.3**	**$ 16.7**	**$ 10.8**	**$ 2.8**	**$ (0.3)**	**$ (14.7)**	**$ (8.2)**	**$ (23.1)**	**$ (22.4)**	**$ (2,171.5)**
Total Gen. Body of Customers Net RevReqs (fav) unfav	87.3%	**$ (465.1)**	**$ (2,862.2)**	**$ 1.0**	**$ 21.6**	**$ 59.2**	**$ 84.2**	**$ 73.7**	**$ 61.6**	**$ 29.7**	**$ 4.2**	**$ (8.9)**	**$ (7.7)**	**$ (21.0)**	**$ (25.5)**	**$ (3,134.2)**

(1) System Impacts - Includes avoided generation capital, transmission capital, fixed O&M, and gas reservation charges

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 8
PARTY: TGF-1
DESCRIPTION: Summary of CEC Program Revenue Requirements, Subscription Fees, and Bill Credits.

Clean Tariffs:
6.101, 6.405, 6.406,
and 6.407

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 9
PARTY: LH-1
DESCRIPTION: Clean and Legislative Versions of Tariff sheets 6.101, 6.405, 6.406, and 6.407

INDEX OF RATE SCHEDULES

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM

Availability:

The Clean Energy Connection Rider ("the Program") is available to all Customers throughout the entire service area served by Duke Energy Florida (DEF) subject to subscription availability. This optional Program allows customers to subscribe to a portion of universal solar capacity built for the benefit of the Program and receive bill credits for the actual solar production associated with their subscription.

Applicable:

This optional rider is offered in conjunction with the applicable rates, terms, and conditions under which the Customer takes service from DEF. All rates and charges under the Customers' otherwise applicable metered rate schedule shall apply.

Limitation of Service:

Any Customer account taking service under another Company rate schedule whose account is current is eligible to participate. Eligible Customers may elect a subscription level in 1 kW units representing up to 100% of their previous 12-month total kWh usage. Increases in number of units purchased will be limited to once per rolling 12-month period from the anniversary date of program enrollment, and subject to program availability. Customers who present proof of participation in local, state, or federal assistance are eligible for participation at the low-income pricing provided by this tariff.

Rate:

The Monthly Subscription shall be equal to the sum of the Monthly Subscription Fee + Monthly Bill Credit as follows:

Monthly Subscription			
Participant		Low-Income Participant	
Subscription Rate $/kW-Month	Bill Credit Rate ¢/kWh	Subscription Rate $/kW-Month	Bill Credit Rate $/kW-Month
See Sheet No. 6.407	See Sheet No. 6.407	See Sheet No. 6.407	See Sheet No. 6.407

Notes:

(1) Monthly Bill Credit amounts resulting in a total bill below the minimum monthly bill will have any excess credit amounts applied to subsequent monthly bill amounts.

Minimum Monthly Bill:

The minimum monthly bill shall be the customer's minimum bill under the applicable Rate Schedule. The Monthly Subscription Fee and offsetting Monthly Bill Credit will appear as separate line items on the participant's bill during every month of enrollment, and are subject to all applicable taxes and fees.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

The term of service will be no less than one (1) billing cycle. Participants may at any time following their first billing cycle, terminate their participation or reduce the number of subscribed units purchased. Participants may be terminated from the program by DEF if the Customer becomes delinquent on the Customer's electric service account, enters into a payment arrangement plan, or for failure to satisfy eligibility requirements. Upon termination, whether initiated by Customer or by DEF, the account is prohibited from re-enrolling for a twelve (12) month period.

Special Provisions:

1. In the event that the Customer transfers their electric service to a different location within DEF's service area, the Customer's subscription shall be transferred to the new service location unless the Customer notifies DEF otherwise.

2. Customers shall not be permitted to redirect Bill Credits or transfer the obligation to pay Subscription Fees to other Duke Energy customer accounts, nor will DEF assign Bill Credits or Subscription Fees to any party other than the original subscribing Customer.

3. Participation in this Program does not convey to the Customer any right, title or interest in or to any portion of the property comprising of any Duke Energy owned solar facilities or any solar facilities constructed pursuant to the Program.

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM
(Continued From Page No. 1)

4. All solar plants allocated to the Program will be registered with the North America Renewables Registry (NAR) and renewable energy credits (RECs) retired on behalf of all participating Customers on a yearly basis. Upon Customer's request, DEF will move the RECs associated with the Customer's subscription to the Customer's account, at the Customer's expense. Notification to move RECs must be made by the Customer to DEF. RECs will be moved after the payment of the fee. Once a REC is retired on behalf of all participants, it cannot be moved into an individual Customer's account.

5. Subscription Fees and Bill Credits received for additional subscriptions, after a Customer election to increase the number of units purchased, shall begin in Participant Program Year One (1), while previously held subscriptions remain on the Participant Program Year that pertains to the date of the Customer's original subscription.

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM
(Continued From Page No. 2)

MONTHLY SUBSCRIPTION
COMMUNITY SOLAR PROGRAM PARTICIPANT RATES

Phase 1				
	Participant		Low-Income Participant	
Participant Program Year	Subscription Rate $/kW-Month	Bill Credit Rate ¢/kWh	Subscription Rate $/kW-Month	Bill Credit Rate $/kW-Month
1	$8.35	(4.0370)	$8.35	($9.03)
2	$8.35	(4.0370)	$8.35	($9.03)
3	$8.35	(4.0370)	$8.35	($9.03)
4	$8.35	(4.0980)	$8.35	($9.03)
5	$8.35	(4.1590)	$8.35	($9.03)
6	$8.35	(4.2210)	$8.35	($9.03)
7	$8.35	(4.2840)	$8.35	($9.03)
8	$8.35	(4.3480)	$8.35	($9.03)
9	$8.35	(4.4130)	$8.35	($9.03)
10	$8.35	(4.4790)	$8.35	($9.03)
11	$8.35	(4.5460)	$8.35	($9.03)
12	$8.35	(4.6140)	$8.35	($9.03)
13	$8.35	(4.6830)	$8.35	($9.03)
14	$8.35	(4.7530)	$8.35	($9.03)
15	$8.35	(4.8240)	$8.35	($9.03)
16	$8.35	(4.8960)	$8.35	($9.03)
17	$8.35	(4.9690)	$8.35	($9.03)
18	$8.35	(5.0440)	$8.35	($9.03)
19	$8.35	(5.1200)	$8.35	($9.03)
20	$8.35	(5.1970)	$8.35	($9.03)
21	$8.35	(5.2750)	$8.35	($9.03)
22	$8.35	(5.3540)	$8.35	($9.03)
23	$8.35	(5.4340)	$8.35	($9.03)
24	$8.35	(5.5160)	$8.35	($9.03)
25	$8.35	(5.5990)	$8.35	($9.03)
26	$8.35	(5.6830)	$8.35	($9.03)
27	$8.35	(5.7680)	$8.35	($9.03)
28	$8.35	(5.8550)	$8.35	($9.03)
29	$8.35	(5.9430)	$8.35	($9.03)
30	$8.35	(6.0320)	$8.35	($9.03)
31	$8.35	(6.0320)	$8.35	($9.03)
32	$8.35	(6.0320)	$8.35	($9.03)

Legislative Tariffs:
6.101, 6.405,
6.406, and 6.407

INDEX OF RATE SCHEDULES

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM

Availability:

The Clean Energy Connection Rider ("the Program") is available to all Customers throughout the entire service area served by Duke Energy Florida (DEF) subject to subscription availability. This optional Program allows customers to subscribe to a portion of universal solar capacity built for the benefit of the Program and receive bill credits for the actual solar production associated with their subscription.

Applicable:

This optional rider is offered in conjunction with the applicable rates, terms, and conditions under which the Customer takes service from DEF. All rates and charges under the Customers' otherwise applicable metered rate schedule shall apply.

Limitation of Service:

Any Customer account taking service under another Company rate schedule whose account is current is eligible to participate. Eligible Customers may elect a subscription level in 1 kW units representing up to 100% of their previous 12-month total kWh usage. Increases in number of units purchased will be limited to once per rolling 12-month period from the anniversary date of program enrollment, and subject to program availability. Customers who present proof of participation in local, state, or federal assistance are eligible for participation at the low-income pricing provided by this tariff.

Rate:

The Monthly Subscription shall be equal to the sum of the Monthly Subscription Fee + Monthly Bill Credit as follows:

Monthly Subscription			
Participant		Low-Income Participant	
Subscription Rate $/kW-Month	Bill Credit Rate ¢/kWh	Subscription Rate $/kW-Month	Bill Credit Rate $/kW-Month
See Sheet No. 6.407	See Sheet No. 6.407	See Sheet No. 6.407	See Sheet No. 6.407

Notes:

(1) Monthly Bill Credit amounts resulting in a total bill below the minimum monthly bill will have any excess credit amounts applied to subsequent monthly bill amounts.

Minimum Monthly Bill:

The minimum monthly bill shall be the customer's minimum bill under the applicable Rate Schedule. The Monthly Subscription Fee and offsetting Monthly Bill Credit will appear as separate line items on the participant's bill during every month of enrollment, and are subject to all applicable taxes and fees.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

The term of service will be no less than one (1) billing cycle. Participants may at any time following their first billing cycle, terminate their participation or reduce the number of subscribed units purchased. Participants may be terminated from the program by DEF if the Customer becomes delinquent on the Customer's electric service account or for failure to satisfy eligibility requirements. Upon termination, whether initiated by Customer or by DEF, the account is prohibited from re-enrolling for a twelve (12) month period.

Special Provisions:

1. In the event that the Customer transfers their electric service to a different location within DEF's service area, the Customer's subscription shall be transferred to the new service location unless the Customer notifies DEF otherwise.

2. Customers shall not be permitted to redirect Bill Credits or transfer the obligation to pay Subscription Fees to other Duke Energy customer accounts, nor will DEF assign Bill Credits or Subscription Fees to any party other than the original subscribing Customer.

3. Participation in this Program does not convey to the Customer any right, title or interest in or to any portion of the property comprising of any Duke Energy owned solar facilities or any solar facilities constructed pursuant to the Program.

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM
(Continued From Page No. 1)

4. All solar plants allocated to the Program will be registered with the North America Renewables Registry (NAR) and renewable energy credits (RECs) retired on behalf of all participating Customers on a yearly basis. Upon Customer's request, DEF will move the RECs associated with the Customer's subscription to the Customer's account, at the Customer's expense. Notification to move RECs must be made by the Customer to DEF. RECs will be moved after the payment of the fee. Once a REC is retired on behalf of all participants, it cannot be moved into an individual Customer's account.

5. Subscription Fees and Bill Credits received for additional subscriptions, after a Customer election to increase the number of units purchased, shall begin in Participant Program Year One (1), while previously held subscriptions remain on the Participant Program Year that pertains to the date of the Customer's original subscription.

RATE SCHEDULE CEC-1
CLEAN ENERGY CONNECTION RIDER
OPTIONAL SOLAR PROGRAM
(Continued From Page No. 2)

MONTHLY SUBSCRIPTION
COMMUNITY SOLAR PROGRAM PARTICIPANT RATES

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31	$8.35	(6.0320)	$8.35	($9.03)
32	$8.35	(6.0320)	$8.35	($9.03)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.	**:**	**DOCKET NO. 20200176-EI**
	:	
	:	
	:	**Filed: October 2, 2020**

EXHIBIT SWC-1 OF

STEVE W. CHRISS

ON BEHALF OF

WALMART INC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 10
PARTY: SWC-1
DESCRIPTION: Witness Qualifications Statement

Steve W. Chriss

Walmart Inc.
Business Address: 2608 SE J Street, Bentonville, AR, 72716

EXPERIENCE
July 2007 – Present
Walmart Inc., Bentonville, AR
Director, Energy Services (October 2018 – Present)
Director, Energy and Strategy Analysis (October 2016 – October 2018)
Senior Manager, Energy Regulatory Analysis (June 2011 – October 2016)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

PRESENT MEMBERSHIPS
Arizona Independent Scheduling Administrators Association, Board
Arizonans for Electric Choice & Competition, Chairman
Edison Electric Institute National Key Accounts Program, Customer Advisory Group
Florida Advisory Council for Climate and Energy
Renewable Energy Buyers Alliance, Advisory Board

PAST MEMBERSHIPS
Southwest Power Pool, Corporate Governance Committee, 2019

TESTIMONY BEFORE REGULATORY COMMISSIONS
2020
Florida Docket No. 20200092-EI: In re: Storm Protection Plan Cost Recovery Clause.

Nevada Docket No. 20-05003: Application of Nevada Power Company d/b/a NV Energy Filed Under Advice Letter No. 504 to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist

Certain Qualifying Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Nevada Docket No. 20-05004: Application of Sierra Pacific Power Company d/b/a NV Energy Filed Under Advice Letter No. 629-E to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist Certain Qualifying Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Utah Docket No. 20-035-04: Application of Rocky Mountain Power for the Authority to Increase its Retail Electric Utility Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Wyoming Docket No. 20000-578-ER-20: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4.

Virginia Case No. PUR-2020-00015: Application of Appalachian Power Company for a 2020 Triennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services Pursuant to §56-585.1 A of the Code of Virginia.

Oregon Docket No. UE 374: In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision.

Florida Docket No. 20200067-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.

Florida Docket No. 20200069-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

Florida Docket No. 20200070-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.

Florida Docket No. 20200071-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.

North Carolina Docket No. E-2, Sub 1219: Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.
Missouri Case No. ER-2019-0374: In the Matter of the Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area.

North Carolina Docket No. E-7, Sub 1214: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Texas Docket No. 49831: Application of Southwestern Public Service Company for Authority to Change Rates.

2019

Missouri Case No. ER-2019-0335: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease its Revenues for Electric Service.

Michigan Case No. U-20561: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Indiana Cause No. 45253: Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, For (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes.

Arizona Docket No. E-01933A-19-0228: In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.

Georgia Docket No. 42516: In Re: Georgia Power's 2019 Rate Case.

Colorado Proceeding No. 19AL-0268E: Re: In the Matter of Advice No. 1797-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8-Electric Tariff to Implement Rate Changes Effective on Thirty Days' Notice.

New York Case No. 19-E-0378: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 19-E-0380: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

Maryland Case No. 9610: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.

Nevada Docket No. 19-06002: In the Matter of the Application by Sierra Pacific Power Company, D/B/A NV Energy, Filed Pursuant to NRS 704.110(3) and NRS 704.110(4), Addressing its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers.

Florida Docket No. 20190061-EI: In Re: Petition of Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff.

Wisconsin Docket No. 6690-UR-126: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates – Test Year 2020.

Wisconsin Docket No. 5-UR-109: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates – Test Year 2020.

New Mexico Case No. 19-00158-UT: In the Matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561.

Indiana Cause No. 45235: Petition of Indiana Michigan Power Company, and Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion in Rate Base of Qualified Pollution Control Property and Clean Energy Project; (4) Enhancements to the Dry Sorbent Injection System; (5) Advanced Metering Infrastructure; (6) Rate Adjustment Mechanism Proposals; and (7) New Schedules of Rates, Rules and Regulations.

Iowa Docket No. RPU-2019-0001: In Re: Interstate Power and Light Company.

Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.

Arkansas Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Virginia Case No. PUR-2019-00050: Application of Virginia Electric and Power Company for Determination of the Fair Rate of Return on Common Equity Pursuant to § 56-585.1:1 of the Code of Virginia.

Indiana Docket No. 45159: Petition of Northern Indiana Public Service Company LLC Pursuant to Indiana Code §§ 8-1-2-42.7, 8-1-2-61 and Indiana Code §§ 1-2.5-6 for (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase In of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief; and (5) Approval of a New Service Structure for Industrial Rates.

Texas Docket No. 49421: Application of Centerpoint Energy Houston Electric, LLC for Authority to Change Rates.

Nevada Docket No. 18-11015: Re: Application of Nevada Power Company d/b/a NV Energy, Filed Under Advice No. 491, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Nevada Docket No. 18-11016: Re: Application of Sierra Pacific Power Company d/b/a NV Energy, Filed Under Advice No. 614-E, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Georgia Docket No. 42310: In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity From Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant Mcintosh Unit 1, Plant Langdale Units 5-6, Plant Riverview Units 1-2, and Plant Estatoah Unit 1.

Wyoming Docket Nos. 20003-177-ET-18: In the Matter of the Application of Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy For Approval to Implement a Renewable Ready Service Tariff.

South Carolina Docket No. 2018-318-E: In the Matter of the Application of Duke Energy Progress, LLC For Adjustments in Electric Rate Schedules and Tariffs.

Montana Docket No. D2018.2.12: Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.

Louisiana Docket No. U-35019: In Re: Application of Entergy Louisiana, LLC for Authorization to Make Available Experimental Renewable Option and Rate Schedule ERO.

Arkansas Docket No. 18-037-TF: In the Matter of the Petition of Entergy Arkansas, Inc. For Its Solar Energy Purchase Option.

2018
South Carolina Docket No. 2017-370-E: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for Review and Approval of a Proposed Business Combination Between SCANA Corporation and Dominion Energy, Inc., as may be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans.

Kansas Docket No. 18-KCPE-480-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Virginia Case No. PUR-2017-00173: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Virginia Case No. PUR-2017-00174: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Oregon Docket No. UM 1953: In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100% Renewable Energy Rider Pursuant to § 56-577.A.5 of the Code of Virginia.

Missouri Docket No. ER-2018-0145: In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Missouri Docket No. ER-2018-0146: In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Kansas Docket No. 18-WSEE-328-RTS: In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Oregon Docket No. UE 335: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

North Dakota Case No. PU-17-398: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100 Percent Renewable Energy Rider Pursuant to § 56-577 A 5 of the Code of Virginia.

Missouri Case No. ET-2018-0063: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.

New Mexico Case No. 17-00255-UT: In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 272.

Virginia Case No. PUR-2017-00157: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-Residential Customers.

Kansas Docket No. 18-KCPE-095-MER: In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.

North Carolina Docket No. E-7, Sub 1146: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Louisiana Docket No. U-34619: In Re: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or/1994 General Orders.

Missouri Case No. EM-2018-0012: In the Matter of the Application of Great Plains Energy Incorporated for Approval of its Merger with Westar Energy, Inc.

2017
Arkansas Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.

Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project.

Oklahoma Cause No. PUD 201700267: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Wind Catcher Energy Connection Project; A Determination There is Need for the Project; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the Project; Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; Waiver of OAC 165:35-38-5(E); And Such Other Relief the Commission Deems PSO is Entitled.

Nevada Docket No. 17-06003: In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, Filed Pursuant to NRS 704.110(3) and (4), Addressing Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers.

North Carolina Docket No. E-2, Sub 1142: In the Matter of the Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Oklahoma Cause No. PUD 201700151: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Kentucky Case No. 2017-00179: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Requested Relief.

New York Case No. 17-E-0238: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service.

Virginia Case No. PUR-2017-00060: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.

New Jersey Docket No. ER17030308: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto, and for Other Appropriate Relief.

Texas Docket No. 46831: Application of El Paso Electric Company to Change Rates.

Oregon Docket No. UE 319: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

New Mexico Case No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice No. 533.

Minnesota Docket No. E015/GR-16-664: In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota.

Ohio Case No. 16-1852-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.

Texas Docket No. 46449: Application of Southwestern Electric Power Company for Authority to Change Rates.

Arkansas Docket No. 16-052-U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges, and Tariffs.

Missouri Case No. EA-2016-0358: In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345 kV Transmission Line.

Florida Docket No. 160186-Ei: In Re: Petition for Increase in Rates by Gulf Power Company.

2016
Missouri Case No. ER-2016-0179: In the Matter of Union Electric Company d/b/a Ameren Missouri Tariffs to Increase its Revenues for Electric Service.

Kansas Docket No. 16-KCPE-593-ACQ: In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated.

Missouri Case No. EA-2016-0208: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Distributed Solar Program and File Associated Tariff.

Utah Docket No. 16-035-T09: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff.

Pennsylvania Public Utility Commission Docket No. R-2016-2537359: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537352: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537355: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537349: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Michigan Case No. U-17990: In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Florida Docket No. 160021-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

Minnesota Docket No. E-002/GR-15-816: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota.

Colorado Public Utilities Commission Docket No. 16AL-0048E: Re: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No.7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

Colorado Public Utilities Commission Docket No. 16A-0055E: Re: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.

Missouri Public Service Commission Case No. ER-2016-0023: In the Matter of the Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.

Georgia Public Service Commission Docket No. 40161: In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT.

Oklahoma Corporation Commission Cause No. PUD 201500273: In the Matter of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

New Mexico Case No. 15-00261-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513.

2015
Indiana Utility Regulatory Commission Cause No. 44688: Petition of Northern Indiana Public Service Company for Authority to Modify its Rates and Charges for Electric Utility Service and for Approval of: (1) Changes to its Electric Service Tariff Including a New Schedule of Rates and Charges and Changes to the General Rules and Regulations and Certain Riders; (2) Revised Depreciation Accrual Rates; (3) Inclusion in its Basic Rates and Charges of the Costs Associated with Certain Previously Approved Qualified Pollution Control Property, Clean Coal Technology, Clean Energy Projects and Federally Mandated Compliance Projects; and (4) Accounting Relief to Allow NIPSCO to Defer, as a Regulatory Asset or Liability, Certain Costs for Recovery in a Future Proceeding.

Public Utility Commission of Texas Docket No. 44941: Application of El Paso Electric Company to Change Rates.

Arizona Corporation Commission Docket No. E-04204A-15-0142: In the matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realized a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to its Operations Throughout the State of Arizona, and for Related Approvals.

Rhode Island Public Utilities Commission Docket No. 4568: In Re: National Grid’s Rate Design Plan.

Oklahoma Corporation Commission Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Public Service Commission of Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Public Service Commission Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Public Service Commission Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company’s Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Public Service Commission of Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Corporation Commission Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Public Service Commission Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Public Utility Commission of Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Corporation Commission Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

2014
Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.

Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428743: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Public Service Commission of Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012
Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011
Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010
Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. UE-100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ*., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ*. and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009
Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008
Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

2007
Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

2004
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

TESTIMONY BEFORE LEGISLATIVE BODIES

2020

Regarding Missouri Senate Joint Resolution 34: Written testimony submitted to the Missouri Senate Transportation, Infrastructure and Public Safety Committee, January 30, 2020.

2019

Regarding North Carolina Senate Bill 559: Written testimony submitted to the North Carolina Committee on Agriculture/Environment/Natural Resources, April 17, 2019.

Regarding Missouri Senate Joint Resolution 25: Written testimony submitted to the Missouri Senate Committee on Judiciary, March 28, 2019.

Regarding South Carolina House Bill 3659: Written testimony submitted to the South Carolina Senate Committee on Judiciary, March 14, 2019.

Regarding Kansas Senate Bill 69: Written testimony submitted to the Kansas Committee on Utilities, February 19, 2019.

2018

Regarding Missouri Senate Bill 564: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 10, 2018.

2017

Regarding Missouri Senate Bill 190: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 25, 2017.

2016

Regarding Missouri House Bill 1726: Testimony before the Missouri House Energy and Environment Committee, April 26, 2016.

2014

Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

2012

Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011

Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS

2015

Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, COVID-19, a Catalyzer or a Barrier to Decarbonization?, Power & Renewables Summit 2020, September 28, 2020.

Panelist, What Organized Markets Can Do for You, REBA Connect: Virtual Member Summit 2020, June 2, 2020.

Panelist, Expanding Future Procurement Options, REBA Connect: Virtual Member Summit 2020, May 13, 2020.

Panelist, Renewable Energy Options for Large Utility Customers, NARUC Center for Partnership & Innovation Webinar Series, January 16, 2020.

Panelist, Pathways to Integrating Customer Clean Energy Demand in Utility Planning, REBA: Market Innovation webinar, January 13, 2020.

Panelist, Should Full Electrification of Energy Systems be Our Goal? If it's No Longer Business as Usual, What Does That Mean for Consumers?, National Association of State Utility Consumer Advocates 2019 Annual Meeting, San Antonio, Texas, November 18, 2019.

Panelist, Fleet Electrification, Federal Utility Partnership Working Group Seminar, Washington, DC, November 8, 2019.

Panelist, Tackling the Challenges of Extreme Weather, Edison Electric Institute Fall National Key Accounts Workshop, Las Vegas, Nevada, October 8, 2019.

Panelist, Fleet Electrification: Tackling the Challenges and Seizing the Opportunities for Electric Trucks, Powering the People 2019, Washington, D.C., September 24, 2019.

Panelist, From the Consumer Perspective, Mid-American Regulatory Conference 2019 Annual Meeting, Des Moines, Iowa, August 13, 2019.

Panelist, Redefining Resiliency: Emerging Technologies Benefiting Customers and the Grid, EPRI 2019 Summer Seminar, Chicago, Illinois, August 12, 2019.

Panelist, Energy Policies for Economic Growth, 2019 Energy Policy Summit, NCSL Legislative Summit, Nashville, Tennessee, August 5, 2019.

Panelist, Gateway to Energy Empowerment for Customers, Illumination Energy Summit, Columbus, Ohio, May 15, 2019.

Panelist, Advancing Clean Energy Solutions Through Stakeholder Collaborations, 2019 State Energy Conference of North Carolina, Raleigh, North Carolina, May 1, 2019.

Panelist, Fleet Electrification: Getting Ready for the Transition, Edison Electric Institute Spring National Key Accounts Workshop, Seattle, Washington, April 8, 2019.

Panelist, Where the Fleet Meets the Pavement, Which Way to Electrification of the U.S. Transportation System?, Washington, D.C., April 4, 2019.

Panelist, Improving Renewable Energy Offerings: What Have We Learned?, Advanced Energy Economy Webinar, March 26, 2019.

Speaker, National Governors Association Southeast Regional Transportation Electrification Workshop, Nashville, Tennessee, March 11, 2019.

Speaker, Walmart Spotlight: A Day in the Life of a National Energy Manager, Touchstone Energy Cooperatives Net Conference 2019, San Diego, California, February 12, 2019.

Panelist, National Accounts: The Struggle is Real, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Getting in Front of Customers Getting Behind the Meter Solutions, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Sustainable Fleets: The Road Ahead for Electrifying Fleet Operations, EEI National Key Accounts 2018 Fall Workshop, San Antonio, Texas, October 23, 2018.

Panelist, Meeting Corporate Clean Energy Requirements in Virginia, Renewable Energy Buyers Alliance Summit, Oakland, California, October 15, 2018.

Panelist, What Are the Anticipated Impacts on Pricing and Reliability in the Changing Markets?, Southwest Energy Conference, Phoenix, Arizona, September 21, 2018.

Speaker, Walmart's Project Gigaton – Driving Renewable Energy Sourcing in the Supply Chain, Smart Energy Decisions Webcast Series, July 11, 2018.

Panelist, Customizing Energy Solutions, Edison Electric Institute Annual Convention, San Diego, California, June 7, 2018.

Powering Ohio Report Release, Columbus, Ohio, May 29, 2018.

Panelist, The Past, Present, and Future of Renewable Energy: What Role Will PURPA, Mandates, and Collaboration Play as Renewables Become a Larger Part of Our Energy Mix?, 36th National Regulatory Conference, Williamsburg, Virginia, May 17, 2018.

Panelist, Sustainability Milestone Deep Dive Session, Walmart Global Sustainability Leaders Summit, Bentonville, Arkansas, April 18, 2018.

Panelist, The Customer's Voice, Tennessee Valley Authority Distribution Marketplace Forum, Murfreesboro, Tennessee, April 3, 2018.

Panelist, Getting to Yes with Large Customers to Meet Sustainability Goals, The Edison Foundation Institute for Electric Innovation Powering the People, March 7, 2018.

Panelist, The Corporate Quest for Renewables, 2018 NARUC Winter Policy Summit, Washington, D.C., February 13, 2018.

Panelist, Solar and Renewables, Touchstone Energy Cooperatives NET Conference 2018, St. Petersburg, Florida, February 6, 2018.

Panelist, Missouri Public Service Commission November 20, 2017 Workshop in File No. EW-2017-0245.

Panelist, Energy and Climate Change, 2017-18 Arkansas Law Review Symposium: Environmental Sustainability and Private Governance, Fayetteville, Arkansas, October 27, 2017.

Panelist, Customer – Electric Company – Regulator Panel, Edison Electric Institute Fall National Key Accounts Workshop, National Harbor, Maryland, October 12, 2017.

Panelist, What Do C&I Buyers Want, Solar Power International, Las Vegas, Nevada, September 12, 2017.

Panelist, Partnerships for a Sustainable Future, American Public Power Association National Conference, Orlando, Florida, June 20, 2017.

Panelist, Corporate Renewable Energy Buyers in the Southeast, SEARUC 2017, Greensboro, Georgia, June 12, 2017.

Panelist, Transitioning Away from Traditional Utilities, Utah Association of Energy Users Annual Conference, Salt Lake City, Utah, May 18, 2017.

Panelist, Regulatory Approaches for Integrating and Facilitating DERs, New Mexico State University Center for Public Utilities Advisory Council Current Issues 2017, Santa Fe, New Mexico, April 25, 2017.

Presenter, Advancing Renewables in the Midwest, Columbia, Missouri, April 24, 2017.

Panelist, Leveraging New Energy Technologies to Improve Service and Reliability, Edison Electric Institute Spring National Key Accounts Workshop, Phoenix, Arizona, April 11, 2017.

Panelist, Private Sector Demand for Renewable Power, Vanderbilt Law School, Nashville, Tennessee, April 4, 2017.

Panelist, Expanding Solar Market Opportunities, 2017 Solar Power Colorado, Denver, Colorado, March 15, 2017.

Panelist, Renewables: Are Business Models Keeping Up?, Touchstone Energy Cooperatives NET Conference 2017, San Diego, California, January 30, 2017.

Panelist, The Business Case for Clean Energy, Minnesota Conservative Energy Forum, St. Paul, Minnesota, October 26, 2016.

Panelist, M-RETS Stakeholder Summit, Minneapolis, Minnesota, October 5, 2016.

Panelist, 40th Governor's Conference on Energy & the Environment, Kentucky Energy and Environment Cabinet, Lexington, Kentucky, September 21, 2016.

Panelist, Trends in Customer Expectations, Wisconsin Public Utility Institute, Madison, Wisconsin, September 6, 2016.

Panelist, The Governor's Utah Energy Development Summit 2015, May 21, 2015.

Mock Trial Expert Witness, The Energy Bar Association State Commission Practice and Regulation Committee and Young Lawyers Committee and Environment, Energy and Natural Resources Section of the D.C. Bar, Mastering Your First (or Next) State Public Utility Commission Hearing, February 13, 2014.

Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.

Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.	:	**DOCKET NO. 20200176-EI**
	:	
	:	
	:	**Filed: October 2, 2020**

EXHIBIT SWC-2 OF

STEVE W. CHRISS

ON BEHALF OF

WALMART INC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 11
PARTY: SWC-2
DESCRIPTION: Stipulation (July 20, 2020, filed in connection with Storm Protection Plan Dockets)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.	:	**DOCKET NO. 20200067-EI**
In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.	:	**DOCKET NO. 20200069-EI**
In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.	:	**DOCKET NO. 20200070-EI**
In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.	:	**DOCKET NO. 20200071-EI** **Filed: July 20, 2020**

STIPULATION

WHEREAS, Walmart Inc. ("Walmart"), Tampa Electric Company ("TECO"), Duke Energy Florida, LLC ("DEF"), Gulf Power Company ("Gulf"), and Florida Power & Light Company ("FPL") (collectively, "Companies") have signed this Stipulation;

WHEREAS, on April 29, 2020, Walmart submitted Petitions to Intervene in the four Storm Protection Plan ("SPP") Dockets: 20200067-EI (TECO); 20200069-EI (DEF); 20200070 (Gulf); and 20200071 (FPL) (collectively, "SPP Dockets");

WHEREAS, on July 13 2020, Walmart submitted its proposed Issues to the parties for inclusion in Staff's Issues list for the Hearing, which Issues were supported by Walmart's pre-filed Direct Testimony of its witnesses Steve W. Chriss and Lisa V. Perry, filed May 26, 2020;

WHEREAS, one of the proposed Issues that Walmart submitted was as follows:

Issue No. 1 Should the Commission reject the proposed illustrative SPP rate designs of DEF and Gulf, which recover SPP costs from demand-metered customers through a $/kWh energy charge or defer that issue to the SPP Clause Docket, 20200092-EI?;

WHEREAS, on July 16, 2020, the parties participated in an Informal Conference during which the Companies and Staff opined that Walmart's proposed Issue No. 1 was an issue for the SPP Clause Docket, 20200092-EI;

WHEREAS, following the Informal Conference, Walmart contacted all interested parties regarding their position on its proposed Stipulation. The Office of Public Counsel and Florida Industrial Power Users Group indicated that they do not take a position. White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs has not responded as of the time of this filing; and

WHEREAS, based upon the Companies' agreement to defer the Issue, Walmart agrees to defer proposed Issue No. 1 to the SPP Clause Docket, 20200092-EI, upon entry of a Stipulation to that effect.

THEREFORE, Walmart hereby stipulates that its Issue No. 1 may be withdrawn from the SPP Dockets and deferred for the Commission's consideration in the SPP Clause Docket, 20200092-EI, and agrees that the parties may offer revisions to the phrasing of the issue in that Docket in accordance with the standard issue identification process.

July 20, 2020

By *<u>/s/Stephanie U. Eaton</u>*

Stephanie U. Eaton (FL State Bar No. 165610)
SPILMAN THOMAS & BATTLE, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
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Counsel to Walmart Inc.

By */s/Malcolm N. Means*

James D. Beasley
J. Jeffrey Wahlen
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Counsel to Tampa Electric Company

By */s/Matthew R. Bernier*

Matthew R. Bernier
Duke Energy Florida, LLC
106 East College Avenue, Suite 800
Tallahassee, FL 32301
matthew.bernier@duke-energy.com

Counsel to Duke Energy Florida, LLC

By */s/Christopher T. Wright*

Christopher T. Wright
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
Christopher.wright@fpl.com

Counsel to Gulf Power Company

By */s/Christopher T. Wright*
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Counsel to Florida Power & Light Company

Karl R. Rábago

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rabagoenergy.com | @rabagoenergy

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present.

- Chairman of the Board, Center for Resource Solutions (1997-present).
- Director, Solar United Neighbors (2018-present).

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—Present. Part-time advisor and staff member.

Executive Director: May 2014—August 2019.

- Former Director, Alliance for Clean Energy – New York (2018-2019).
- Former Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Former Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017).

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012.

- Director, Renewable Energy Markets Association.
- Membership on Pedernales Electric Cooperative Member Advisory Board.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008.

- Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC.
- Government and regulatory affairs manager for AES Wind Generation.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006.

- President, Texas Renewable Energy Industries Association.
- Director, Southwest Biofuels Initiative.
- Member, Committee to Study the Environmental Impacts of Windpower.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

Karl R. Rábago

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002.

- President of the Board, Texas Ratepayers Organization to Save Energy.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994.

- Co-chair and organizer of the Texas Sustainable Energy Development Council.
- Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation.
- Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019.

Associate Professor of Law: University of Houston Law Center, 1990–1992.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981.

- Logistics Staff Officer (S-4).
- Support Platoon Leader.
- Platoon Leader, A Troop.

Graduate of Airborne and Ranger Schools.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988.

J.D. with Honors, University of Texas School of Law, 1984.

B.B.A., Business Management, Texas A&M University, 1977.

Selected Publications

Distributed Generation Law, contributing author, American Bar Association Environment, Energy, and Resources Section (August 2020)

National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, contributing author, National Energy Screening Project (August 2020)

Achieving 100% Renewables: Supply-Shaping through Curtailment, with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019)

A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed, with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019)

Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition, with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019)

Revisiting Bonbright's Principles of Public Utility Rates in a DER World, with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018)

Energy Aggregation: Modes, Opportunities, and Challenges, co-author, Renewable, Alternative, and Distributed Energy Resources Committee Newsletter, ABA Section of Environment, Energy, and Resources (July 2018)

Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators, Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016)

The Net Metering Riddle, Electricity Policy.com, April 2016

The Clean Power Plan, Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age, co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

Rethinking the Grid: Encouraging Distributed Generation, Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

The Value of Solar Tariff: Net Metering 2.0, The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, co-author, Interstate Renewable Energy Council (October 2013)

The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff, Solar Industry, Vol. 6, No. 1 (Feb. 2013)

Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development, lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

A Review of Barriers to Biofuels Market Development in the United States, 2 Environmental & Energy Law & Policy Journal 179 (2008)

A Strategy for Developing Stationary Biodiesel Generation, Cumberland Law Review, Vol. 36, p.461 (2006)

Evaluating Fuel Cell Performance through Industry Collaboration, co-author, Fuel Cell Magazine (2005)

Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production, co-author, Polymer Degradation and Stability 80, 403-19 (2003)

An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options, contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, co-author, Rocky Mountain Institute (2002)

Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado, co-author, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

Study of Electric Utility Restructuring in Alaska, co-author, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers, EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

Building a Better Future: Why Public Support for Renewable Energy Makes Sense, Spectrum: The Journal of State Government (Spring 1998)

The Green-e Program: An Opportunity for Customers, co-author, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

Being Virtual: Beyond Restructuring and How We Get There, Contributing author, Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

Information Technology, Public Utilities Fortnightly (March 15, 1996)

Better Decisions with Better Information: The Promise of GIS, with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

The Regulatory Environment for Utility Energy Efficiency Programs, Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

An Alternative Framework for Low-Income Electric Ratepayer Services, with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act, Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

Least Cost Electricity for Texas, State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

Environmental Costs of Electricity, Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 2013	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 13
PARTY: KRR-2
DESCRIPTION: Karl Rábago Prior Testimony

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc. PSCo Rate Application	Wisconsin PSC Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	Virginia SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida PSC Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	Virginia SCC Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island PUC Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	PUC of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	PUC of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors – Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York PSC Case No. 16-E-0060	Pace Energy and Climate Center
June 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy	Invited workshop presentation	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	Virginia SCC Case # PUE-2016-00049	Environmental Respondents
Sep. 13, 2016	Appalachian Power Company 2016 IRP	Virginia SCC Case # PUE-2016-00050	Environmental Respondents
Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan PSC Case No. U-18090	Environmental Law & Policy Center, "Joint Intervenors"
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland PSC Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan PSC Case No. U-18091	Environmental Law & Policy Center, "Joint Intervenors"
Dec. 16, 2016	Rebuttal of Unitil Testimony in Net Energy Metering Docket	New Hampshire Docket No. DE 16-576	New Hampshire Sustainable Energy Association ("NHSEA")
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18089	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18092	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18093	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18094	Environmental Law & Policy Center, "Joint Intervenors"
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts DPU Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts DPU Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	PUC of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana URC Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana URC Cause No. 44645	Citizens Action Coalition
Jul. 28, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana URC Cause No. 44927	Citizens Action Coalition
Aug. 1, 2017	Interstate Power & Light (Alliant) 2017 Rate Application	Iowa Utilities Board Docket No. RPU-2017-0001	Environmental Law & Policy Center, Iowa Environmental Council, Natural Resources Defense Council, and Solar Energy Industries Assoc.
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	Virginia SCC Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	Virginia SCC Case # PUR-2017-00045	Environmental Respondents
Aug. 23, 2017	Pennsylvania Solar Future Project	PA Dept. of Environmental Protection - Alternative Ratemaking Webinar	Pace Energy and Climate Center
Aug. 25, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Sep. 15, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Oct. 20, 2017	Missouri PSC Working Case to Explore Emerging Issues in Utility Regulation	Missouri PSC File No. EW-2017-0245	Renew Missouri
Nov. 21, 2017	Central Hudson Gas & Electric Co. Electric and Gas Rates Cases	New York PSC Case # 17-E-0459, -0460	Pace Energy and Climate Center
Jan. 16, 2018	Great Plains Energy, Inc. Merger with Westar Energy, Inc.	Missouri PSC Case # EM-2018-0012	Renew Missouri Advocates
Jan. 19, 2018	U.S. House of Representatives, Energy and Commerce Committee	Hearing on "The PURPA Modernization Act of 2017," H.R. 4476	Rábago Energy LLC
Jan. 29, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts D.P.U. Case No. 17-140	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Feb. 21, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts D.P.U. Case No. 17-140 - Surrebuttal	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Apr. 6, 2018	Narragansett Electric Co., d/b/a National Grid Rate Case Filing	RI PUC Docket No. 4770	New Energy Rhode Island ("NERI")
Apr. 25, 2018	Narragansett Electric Co., d/b/a National Grid Power Sector Transformation Plan	Rhode Island PUC Docket No. 4780	New Energy Rhode Island ("NERI")
Apr. 26, 2018	U.S. EPA Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Stories: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) – "Clean Power Plan"	U.S. EPA Docket No. EPA-HQ-OAR-2016-0592	Karl R. Rábago
May 25, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York PSC Case Nos. 18-E-0067, 18-G-0068	Pace Energy and Climate Center
Jun. 15, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York PSC Case Nos. 18-E-0067, 18-G-0068 – Rebuttal Testimony	Pace Energy and Climate Center
Aug. 10, 2018	Dominion Virginia Electric Power 2018 IRP	Virginia SCC Case # PUR-2018-00065	Environmental Respondents

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Sep. 20, 2018	Consumers Energy Company Rate Case	Michigan PSC Case No. U-20134	Environmental Law & Policy Center
Sep. 27, 2018	Potomac Electric Power Co. Notice to Construct Two 230 kV Underground Circuits	District of Columbia Public Service Commission Formal Case No. 1144	Solar United Neighbors of D.C.
Sep. 28, 2019	Arkansas Public Service Commission Investigation of Policies Related to Distributed Energy Resources	Arkansas PSC Docket No. 16-028-U	Arkansas Audubon Society & Arkansas Advanced Energy Association
Nov. 7, 2018	DTE Detroit Edison Rate Case	Michigan PSC Case No. U-20162	Natural Resources Defense Council, Michigan Environmental Council, Sierra Club
Mar. 26, 2019	Guam Power Authority Petition to Modify Net Metering	Guam PUC Docket GPA 19-04	Micronesia Renewable Energy, Inc.
Apr. 4, 2019	Community Power Network & League of Women Voters of Florida v. JEA	Circuit Court Duval County of Florida Case No. 2018-CA-002497 Div: CV-D	Earthjustice
Apr. 25, 2019	Georgia Power 2019 IRP	Georgia PSC Docket No. 42310	GSEA & GSEIA
May 10, 2019	NV Energy NV GreenEnergy 2.0 Rider	Nevada PUC Docket Nos. 18-11015, 18-11016	Vote Solar
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Misc. Issues	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Low- and Moderate-Income Panel	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 30, 2019	Connecticut DEEP Shared Clean Energy Facility Program Proposal	Connecticut Department of Energy and Environmental Protection Docket No. 19-07-01	Connecticut Fund for the Environment
Jun. 3, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Jun. 14, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Rebuttal Testimony	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Jun. 24, 2019	Program to Encourage Clean Energy in Westchester County Pursuant to Public Service law Section 74-a; Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory	New York PSC Case Nos. 19-M-0265, 19-G-0080	Earthjustice and Pace Energy and Climate Center
Jul. 12, 2019	Application of Virginia Electric and Power Company for the Determination of the Fair Rate of Return on Common Equity	Virginia SCC Case # PUR-2019-00050	Virginia Poverty Law Center
Jul. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Reply Comments	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Aug. 1, 2019	Interstate Power and Light Company – General Rate Case	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Aug. 19, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Surrebuttal	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
Aug. 21, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources - Comments	Connecticut DEEP/PURA Docket No. 19-06-29	Connecticut Fund for the Environment and Save Our Sound
Sep. 10, 2019	Interstate Power and Light Company – General Rate Case - Rebuttal	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Sep. 18, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Comments and Response to Draft Study Outline	Connecticut DEEP/PURA Docket No. 19-06-29	Connecticut Fund for the Environment, Save Our Sound, E4theFuture, NE Clean Energy Council, NE Energy Efficiency Partnership, and Acadia Center
Sep. 20, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 1	Connecticut DEEP/PURA Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16715	Connecticut Fund for the Environment and Save Our Sound

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Oct. 4, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 2	Connecticut DEEP/PURA Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16766	Connecticut Fund for the Environment and Save Our Sound
Oct. 15, 2019	Electronic Consideration of the Implementation of the Net Metering Act (KY SB 100)	Kentucky Public Service Commission Case No. 2019-00256	Kentuckians for the Commonwealth & Mountain Association for Community Economic Development
Oct. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Comments on City Council Utility Advisors' Report	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana, Vote Solar, 350 New Orleans, Alliance for Clean Energy, PosiGen, and Sierra Club
Oct. 17, 2019	Indiana Michigan Power Co. General Rate Case	Michigan Public Service Company Case No. U-20359	Environmental Law & Policy Center, The Ecology Center, the Solar Energy Industries Association, and Vote Solar
Dec. 4, 2019	Alabama Power Company Petition for Certificate of Convenience and Necessity	Alabama Public Service Commission Docket No. 32953	Energy Alabama and Gasp, Inc.
Dec. 5, 2019	In the Matter of Net Metering and the Implementation of Act 827 of 2015	Arkansas Public Service Commission Docket No. 16-027-R	National Audubon Society and Arkansas Advanced Energy Association
Dec. 6, 2019	Proposed Revisions to Vermont Public Utility Commission Rule 5.100	Vermont Public Utility Commission Case No. 19-0855-RULE	Renewable Energy Vermont ("REV")
Jan. 15, 2020	General Rate Case	Washington Utilities and Transportation Commission Docket Nos. UE-190529 & UG-190530	Puget Sound Energy
Feb. 11, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Direct Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association
Mar. 17, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Surrebuttal Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 31 July 2020)

Jun. 16, 2020	PECO Energy Default Supply Plan V – Direct Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Respondents / Earthjustice
Jun. 24, 2020	Consumers Energy Company General Rate Case – Direct Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
Jul. 14, 2020	Consumers Energy Company General Rate Case – Rebuttal Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
July 23, 2020	PECO Energy Default Supply Plan V – Surrebuttal Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Respondents / Earthjustice

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 14
PARTY: KRR-3
DESCRIPTION: SolarTogether CPVRR Summary

Docket No. 20200176-EI
Solar Together CPVRR summary
Exhibit KRR-3, Page 1 of 1

Docket No. 20190061
Updated CPVRR Analysis for FPL SolarTogether Phase 1
Exhibit SRB-2, Page 1 of 1

($ millions)		CPVRR	Nominal Total	2019	1 2020	2 2021	3 2022	4 2023	5 2024	6 2025	7 2026	8 2027	9 2028	10 2029	11 2030	2031-2051
Discount Factor				1.01	0.93	0.87	0.80	0.75	0.69	0.64	0.60	0.55	0.51	0.48	0.44	
Base Revenue Requirements																
FPL SolarTogether Capital, O&M		$1,792.4	$4,144.6	$3.5	$71.7	$202.2	$210.8	$199.6	$190.8	$183.0	$176.9	$171.9	$167.3	$162.2	$157.3	$2,247.4
Program Administrative Costs		11.5	20.3	2.3	2.1	1.8	1.7	1.1	0.7	0.4	0.3	0.3	0.3	0.3	0.3	8.5
Total FPL SolarTogether Costs		1,803.9	4,164.9	5.8	73.8	204.0	212.4	200.7	191.5	183.4	177.2	172.2	167.6	162.5	157.6	2,256.0
System Impacts (Avoided Generation Capital, O&M)		(544.6)	(1,470.2)	-	(2.0)	(14.8)	(38.2)	(60.4)	(48.3)	(47.0)	(44.5)	(37.4)	(176.3)	(111.1)	(28.0)	(862.1)
Total Base RevReq's (fav) unfav		**$1,259.2**	**$2,694.6**	**$5.8**	**$71.7**	**$189.3**	**$174.3**	**$140.3**	**$143.2**	**$136.5**	**$132.6**	**$134.7**	**($8.7)**	**$51.4**	**$129.6**	**$1,393.8**
Clause Revenue Requirements																
System Net Fuel		($1,049.4)	($3,313.8)	$0.0	($19.6)	($60.6)	($65.6)	($69.8)	($78.8)	($84.2)	($88.3)	($96.4)	($97.6)	($87.9)	($86.6)	($2,478.4)
Incremental Gas Transport		(367.9)	(1,352.4)	-	-	-	-	-	-	-	-	(59.6)	(59.2)	(58.9)	(58.6)	(1,116.0)
Emissions		(90.6)	(514.4)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.7)	(1.2)	(2.4)	(2.6)	(3.6)	(503.7)
Total Clause RevReq's (fav) unfav		**($1,507.9)**	**($5,180.6)**	**$0.0**	**($19.6)**	**($60.7)**	**($65.6)**	**($69.9)**	**($78.9)**	**($84.2)**	**($89.0)**	**($157.1)**	**($159.3)**	**($149.5)**	**($148.8)**	**($4,098.1)**
Net Revenue Requirements (fav) unfav		**($248.6)**	**($2,486.0)**	**$5.8**	**$52.2**	**$128.6**	**$108.6**	**$70.4**	**$64.4**	**$52.3**	**$43.6**	**($22.4)**	**($168.0)**	**($98.1)**	**($19.1)**	**($2,704.3)**
Participant Subscription Charge and Credit	% of Total															
Subscription Charge (Revenue)		($1,315.5)	($3,610.0)	$0.0	($33.1)	($108.3)	($120.3)	($120.3)	($120.3)	($120.3)	($120.3)	($120.3)	($120.3)	($120.3)	($120.3)	($2,385.6)
Subscription Credits		1,452.2	4,288.0	-	31.6	104.8	117.9	119.6	121.5	122.9	124.6	126.4	128.5	129.9	131.7	3,028.6
Participant Net Distribution (Payment)	55.0%	**$136.8**	**$678.0**	**$0.0**	**($1.5)**	**($3.5)**	**($2.4)**	**($0.8)**	**$1.2**	**$2.6**	**$4.3**	**$6.0**	**$8.1**	**$9.6**	**$11.4**	**$643.0**
Revenue Requirements																
Base	% of Total															
Total Base RevReq's		$1,259.2	$2,694.6	$5.8	$71.7	$189.3	$174.3	$140.3	$143.2	$136.5	$132.6	$134.7	($8.7)	$51.4	$129.6	$1,393.8
Participant Subscription (Revenue)	104.47%	(1,315.5)	(3,610.0)	-	(33.1)	(108.3)	(120.3)	(120.3)	(120.3)	(120.3)	(120.3)	(120.3)	(120.3)	(120.3)	(120.3)	(2,385.6)
Net Base RevReq's (fav) unfav	-4.47%	**($56.2)**	**($915.3)**	**$5.8**	**$38.7**	**$81.0**	**$53.9**	**$20.0**	**$22.9**	**$16.1**	**$12.3**	**$14.4**	**($129.0)**	**($68.9)**	**$9.3**	**($991.7)**
Clause	% of Total															
Total Clause RevReq's (fav) unfav		($1,507.9)	($5,180.6)	$0.0	($19.6)	($60.7)	($65.6)	($69.9)	($78.9)	($84.2)	($89.0)	($157.1)	($159.3)	($149.5)	($148.8)	($4,098.1)
Participant Credits	96.31%	1,452.2	4,288.0	-	31.6	104.8	117.9	119.6	121.5	122.9	124.6	126.4	128.5	129.9	131.7	3,028.6
Net Clause RevReq's (fav) unfav	3.69%	**($55.6)**	**($892.6)**	**$0.0**	**$12.0**	**$44.1**	**$52.3**	**$49.7**	**$42.7**	**$38.7**	**$35.6**	**($30.8)**	**($30.8)**	**($19.6)**	**($17.0)**	**($1,069.6)**
Total Net RevReq's (fav) unfav	45.0%	**($111.9)**	**($1,807.9)**	**$5.8**	**$50.7**	**$125.1**	**$106.2**	**$69.7**	**$65.6**	**$54.8**	**$47.9**	**($16.4)**	**($159.8)**	**($88.5)**	**($7.7)**	**($2,061.3)**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190061-EI EXHIBIT: 36
PARTY: FLORIDA POWER & LIGHT COMPANY – REBUTTAL
DESCRIPTION: Scott R. Bores SRB-2

Ten Year Power Plant Site Plan
2020 – 2029

FPL®

Gulf Power®

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Ten Year Power Plant Site Plan

2020-2029

Submitted To:

Florida Public
Service Commission

April 2020

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Table of Contents

List of Figures, Tables, and Maps

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's Preferred and Potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change, at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document addresses both Florida Power & Light Company (FPL) and Gulf Power Company (Gulf). NextEra Energy, the parent company of FPL, acquired Gulf in January 2019. As a result, resource planning for both FPL and Gulf are now performed by FPL's resource planning group. The information presented in this Site Plan is based on integrated resource planning (IRP) analyses that were carried out in 2019 and that were on-going in the first Quarter of 2020. The forecasted information presented in this plan addresses the years 2020 through 2029.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's and Gulf's current generating facilities. Also included is information on other FPL and Gulf resources including purchased power, demand side management (DSM), and FPL's and Gulf's transmission system.

Chapter II – Forecast of Electric Power Demand

The load forecasting methodology utilized for both FPL and Gulf, and the resulting forecast of seasonal peaks and annual energy usage, are presented in Chapter II. Included in this discussion is the projected significant impact of federal and state energy-efficiency codes and standards.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses the integrated resource planning (IRP) process and presents currently projected resource additions in both the FPL and Gulf areas. This chapter also discusses a number of factors or issues that either have changed, or may change, the resource plan presented in this Site Plan. Furthermore, this chapter also discusses previous and planned DSM efforts, the projected significant impact of state/federal energy-efficiency codes and standards, previous and planned renewable energy efforts, projected transmission additions, and the fuel cost forecasting processes.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential Site locations for additional electric generation facilities in both FPL and Gulf areas.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve (12) “discussion items” which pertain to additional information that is included in a Site Plan filing.

List of Abbreviations
Used in Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BS	Battery Storage
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	PV	Photovoltaic
	ST	Steam Unit (Fossil or Nuclear)
Fuel Type	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	NUC	Uranium
	Pet	Petroleum Coke
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	ULSD	Ultra - Low Sulfur Distillate
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	L	Regulatory approval pending. Not under construction
	OP	Operating Unit
	OT	Other
	P	Planned Unit
	RT	Retired
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators
	K Factor	The K factor for the capital costs of a given unit is the cumulative present value of revenue requirements (CPVRR) divided by the total installed cost
	ST	Solar Together
	SoBRA	Solar Rate Base Adjustment

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Executive Summary

This Ten-Year Site Plan (Site Plan) document addresses the projected electric power generating resource additions and retirements for the years 2020 through 2029 for both Florida Power & Light Company (FPL) and Gulf Power Company (Gulf).

On January 1, 2019, Gulf became a subsidiary of NextEra Energy, Inc. which also owns FPL. Prior to this transaction, resource planning analyses for Gulf were performed by Southern Company Services. Among other things, such planning was based on Gulf remaining a part of the Southern Company system. Starting in January 2019, these planning services have been, and will continue to be, performed for both companies by FPL's resource planning group.

NextEra Energy's plan is to integrate FPL and Gulf into a single electric operating system effective on January 1, 2022 after the completion of a new 161 kV transmission line (the North Florida Resiliency Connection line) that will enhance the electrical connection between the two systems. This enhanced connection will benefit customers in both systems by better enabling the siting of clean, reliable, low cost generation, and the transmission of energy from those facilities, to all customers. Consequently, the resource planning work during 2019 and early 2020 that is discussed in this Site Plan has largely focused on developing a resource plan for the single integrated system. However, because this Site Plan addresses two years (2020 and 2021) prior to the scheduled electrical integration of the two systems, a number of schedules and tables will show information for the separate systems for those two years. All information presented for the years 2022 through 2029 is for the single integrated system.[1]

This 2020 Site Plan presents the current plans to augment and enhance the electric generation capability of FPL and Gulf as part of efforts to cleanly, reliably, and cost-effectively meet projected incremental resource needs for 2020 through 2029. FPL already has one of the cleanest emission profiles of any electric utility in the U.S. In 2019, FPL delivered approximately 98% of its energy from a combination of low-emission natural gas, zero-emission nuclear, and zero-emission solar. With the resource additions presented in this Site Plan (which include solar additions consistent with FPL's announced plan to add more than 30 million solar panels by 2030), plus the planned retirement of FPL's ownership portion of a large coal-fueled generating unit, the emission profile of FPL's fleet of generating units is projected to become even cleaner.

[1] In this document, the separate companies will be referred to as FPL and Gulf for the years 2020 and 2021, and the single operating system will be referred to as FPL for the years 2022 through 2029. Likewise, the term "system" is generally used to discuss the separate FPL and Gulf systems for the years 2020 and 2021, and the term "area" is generally used to discuss the FPL and Gulf geographic areas for the years 2022 through 2029.

Although Gulf receives energy from several power purchase agreements that are either solar- or wind-based, the emission profile for Gulf's generation fleet is currently not as good as FPL's. However, this Site Plan describes a number of planned changes regarding generating units in the Gulf area that will significantly improve its emission profile. These planned changes include, but are not limited to, the addition of new solar facilities, enhancing the generation capability of an existing large gas-fueled combined cycle (CC) unit, the conversion of two generating units from coal-fueled to natural gas-fueled, and the retirement of Gulf's ownership portion of two other coal-fueled generating units.

As a result, after accounting for these planned changes to generating units in both FPL's and Gulf's areas, the clean energy percentage for the larger integrated FPL and Gulf utility system is projected to climb to approximately 99% by the end of the 10-year reporting period of this Site Plan.

Furthermore, there is a projected significant increase in the percentage of energy that will be delivered from zero-emission energy sources (solar, wind, and nuclear) over this 10-year reporting period. This is due to a projected significant increased contribution from zero-emission solar over these 10 years while the projected contributions from zero-emission wind and nuclear are projected to remain essentially unchanged.

In 2019, the percentage of the total energy delivered to all customers from both FPL and Gulf that was from zero-emission sources was approximately 22%. By 2029, the last year of the 10-year reporting period addressed in this document, the percentage of the total energy delivered to all customers for the single integrated system from zero-emission sources, including new solar facilities that are associated with FPL's Solar Together program[2], is projected to increase to approximately 37% which represents a 68% increase from 2019. This increase in the percentage of energy that is projected to be delivered by zero-emission sources is significant for a utility system of this size, especially when considering that the total amount of energy projected to be delivered to customers in 2029 will have also increased. The projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 in Chapter III.

By design, the primary focus of this document is on projected supply side additions; *i.e.*, electric generation capability and the sites for these additions. The supply side additions discussed herein are resources projected to be needed after accounting for FPL's and Gulf's demand side management (DSM) resource capabilities and additions. In 2019, the Florida Public Service Commission (FPSC) established DSM Goals for the years 2020 through 2024 for a number of Florida utilities, including FPL and Gulf. Throughout this document, the analysis results discussed are based on an assumption that both companies will meet their respective DSM Goals in regard to Summer MW reduction, Winter MW

[2] In the Solar Together community solar program, participating customers share in the costs and benefits of a dedicated FPL Solar Together PV facility and are entitled, upon their request, to have the environmental attributes associated with their participation retired by FPL on their behalf.

reduction, and annual energy (MWh) reduction through the end of 2024. In addition, further DSM reductions for the years 2025 through 2029 are assumed. DSM is discussed in more detail in Chapters I, II, and III.

Additionally, load forecasts for both FPL and Gulf account for a very large amount of energy efficiency that results from federal and state energy-efficiency codes and standards. The projected impacts of these energy-efficiency codes and standards are discussed later in this summary and in Chapters II and III.

The projected resources, including resource additions and retirements, are summarized in Section I below. In addition, there are a number of factors that either have influenced, or may influence, ongoing resource planning efforts. These factors could result in different resources being added in the future than those presented in this docket. These factors are discussed below in Section II. Additional information regarding the topics is presented in Chapter III.

I. Summary of Projected Resources:

A summary of the projected resources, including resource additions and retirements, in both the FPL and Gulf areas is presented below. This discussion is presented in terms of the various types of resource options (solar, etc.) in the resource plan.

Solar:

At the end of 2019, FPL had a total of approximately 1,228 MW[3] of total solar generation on its system. All of this solar is from FPL-owned solar facilities. Of this total, approximately 1,153 MW is from photovoltaic (PV) facilities and 75 MW are from a solar thermal facility. Also, at the end of 2019, Gulf had a total of 120 MW of solar that is delivered from three PV sites under three power purchase agreements (PPAs).

On November 18, 2019, the FPSC approved (Order No. PSC-2019-0484-FOF-EI) four additional PV facilities for FPL under the SoBRA (Solar Base Rate Adjustment) provision from the 2016 FPL Settlement Agreement (Order No. PSC-2016-0560-AS-EI). Each of these four PV facilities will be 74.5 MW and are scheduled to be in commercial operation in 2020.

This resource plan projects a significant increase in solar (PV) resources during the 10-year reporting period. Approximately 8,860 MW of additional PV generation is projected to be added in the 2020

[3] Each reference to PV capacity in this Site Plan reflects the nameplate rating, AC, unless noted otherwise.

through 2029 time period with approximately 7,300 MW sited in FPL's area and approximately 1,560 MW sited in Gulf's area. These additional PV facilities are projected to be 74.5 MW each. Approximately 1,500 MW of the 7,300 MW of PV projected to be sited in FPL's area is projected to come from FPL's new Solar Together program which was approved by the FPSC on March 3, 2020.

When combining these projected solar additions with the approximately 1,150 MW of solar PV already installed on FPL's system at the end of 2019, the projected total of solar PV for the single integrated utility by the end of 2029 is slightly more than 10,000 MW. This planned solar implementation schedule is consistent with FPL's January 2019 announcement of its "30-by-30" plan in which FPL stated an objective to install more than 30 million solar panels on FPL's system by the year 2030.

This amount of cumulative solar is based on current projections that these solar additions will be cost-effective for FPL's customers. FPL's resource planning work in 2020 and beyond will continue to analyze the projected system economics of solar.[4]

Battery Storage:

In FPL's 2019 Site Plan, the projection was for approximately 469 MW of battery storage to be added in late 2021 with the majority of this battery storage capability projected to be installed in Manatee County as part of the plan to retire the two Manatee steam generating units. These 469 MW of battery storage are also included in this 2020 Site Plan. It is now projected that 409 MW of battery storage will be sited at Manatee as part of this plant retirement effort by late 2021. This battery storage facility will be charged by solar energy from an existing nearby PV facility. The remaining 60 MW of battery storage will be divided into two 30 MW battery storage facilities that will be installed at two different locations in FPL's service area in late 2021. Both of these battery storage facilities will also be charged by existing solar facilities. In addition, the resource plan presented in this Site Plan projects an additional approximately 700 MW of battery storage facilities by 2029 with all of these storage facilities currently projected to be sited in Gulf's area.

FPL continues to analyze other opportunities to utilize battery storage systems, including combining battery storage with new or existing PV facilities. FPL is also evaluating a number of other battery storage applications to gauge the potential for such applications to be beneficial for FPL's customers

[4] System economics of future solar and natural gas-fueled generation will depend upon a number of factors other than future PV costs, including, but not necessarily limited to: natural gas costs, environmental compliance costs, potential technology improvements regarding cost and/or efficiency of both solar and natural gas-fueled generation, and potential system impacts of increasing amounts of solar.

if/when projected cost declines occur. Some of these potential applications are being examined through FPL's 50 MW Battery Storage Pilot Project that is discussed in Chapter III.

Modernization of Non-Renewable Generation:

For a number of years, FPL has undertaken a program to modernize its non-renewable generating units based on cost-effectiveness. These efforts have substantially improved system fuel efficiency and increased capacity while also reducing system air emission rates (including greenhouse gas emission rates) and reducing fuel and other costs for FPL's customers. The plan is to continue this program in both FPL and Gulf areas to further improve the efficiency and capabilities of the fossil-fueled generation fleet in 2020 and beyond through three principal initiatives: (i) retirement of existing generating units that are no longer economic to operate, (ii) enhancements to existing generating units, and (iii) addition of cost-effective new gas-fired generation as appropriate. These three modernization efforts are separately described below.

(i) Retirement of Existing Generating Units That Are No Longer Economic to Operate:

In its 2019 Site Plan, FPL discussed plans to retire two additional steam generating units (Manatee Units 1 & 2) and two older CC units (Lauderdale Units 4 & 5). Similar to two recently retired units at the Martin plant site, each of the Manatee units is approximately 800 MW and the units have become relatively inefficient compared to current generation technology. As a result, FPL's 2019 Site Plan projected that these units would be retired in late 2021. As previously mentioned, a 409 MW battery storage facility will be installed in Manatee County by late 2021 to partially offset the loss of generation in the Manatee area from the retirement of Manatee Units 1 & 2.

The retirement of the Lauderdale Units 4 & 5 has occurred, and these retirements are part of the modernization of FPL's existing Lauderdale power plant site. These two older CC units were each 442 MW units (for a total capacity of approximately 884 MW) that resulted from a repowering project approximately 25 years ago – but which contained certain now-outdated plant components, including the steam turbine, that dated back to the 1950s. These two units will be replaced with a new, modern CC unit that is discussed below. The FPSC voted unanimously to approve this modernization on March 1, 2018. (FPSC Order No. PSC-2018-0150-FOF-EI issued March 19, 2018). The FPSC based its approval on projections of significant economic savings for FPL's customers; enhanced reliability for both the FPL system and the Southeastern Florida region (Miami-Dade and Broward counties) of FPL's service territory; reduced use of natural gas system-wide; and reduced system emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). The Governor and Cabinet, serving as the Power Plant Siting Board, issued a Final Order approving certification of the project on December

13, 2018. Subsequently, the former Fort Lauderdale Units 4 & 5 were retired, and the dismantlement of those facilities has been completed. Construction of the new CC unit, named the Dania Beach Clean Energy Center Unit 7 (Dania Beach), is underway.

The current resource plan presented in this Site Plan continues to account for the retirements of the Manatee units and the new CC unit at the Lauderdale site. In addition, the current resource plan projects the planned early retirements of four coal-fueled generating units. First, the 330 MW power purchase agreement with Indiantown Cogen L.P. is projected to end, along with the retirement of the associated coal-fueled generating unit, in the 4^{th} Quarter of 2020. Second, the retirement of FPL's ownership portion (approximately 76%) of the coal-fueled Scherer Unit 4 unit in Georgia is planned by January 2022. FPL's ownership portion of this unit is approximately 630 MW. Additionally, an early retirement of Gulf's ownership portion (50%) of two coal-fueled steam units by January 2024 is also planned. These units, Daniels Units 1 & 2, are located in the Mississippi Power service territory and Gulf's ownership portion of the two units totals approximately 510 MW.

(ii) <u>Enhancements to Existing Generating Units:</u>

In its 2019 Site Plan, FPL discussed plans to upgrade the combustion turbine (CT) components in a number of FPL's existing CC units. That upgrade effort is still included in the resource plan presented in this Site Plan. An additional multi-year upgrade effort is also now planned. These additional upgrades are projected to be completed in 2026 and will address CC units in both FPL's and Gulf's areas. The upgrades are projected to result in a total increased Summer capacity of approximately 600 MW as well as improved heat rates for each upgraded CC unit. Information regarding the specific units, timing, and magnitude of these upgrades is presented in Schedule 8 in Chapter III.

Two significant enhancements to existing generating units in the Gulf area are also included in the resource plan presented in this Site Plan. The first of those is the conversion of Crist Units 6 & 7 from coal-fueled to natural gas-fueled. This conversion effort is already underway and is scheduled to be completed before the end of 2020**.** This enhancement will result in both lower cost energy generated by the units and in significant fixed cost savings for Gulf area customers. The second enhancement is a pair of capacity upgrades to the Lansing Smith Unit 3. The installation phase of the first upgrade of this existing CC unit was completed in 2019 which will be followed by testing and tuning in the Spring of 2020. This upgrade is projected to increase the firm capacity of the unit by more than 80 MW. A second upgrade of the unit is planned for 2024 which is projected to increase unit capacity by another approximately 59 MW. Both upgrades in this second enhancement will also result in cost savings for Gulf area customers through both the deferral of future capacity needs and by increased output of lower cost natural gas-fueled energy production.

(iii) Addition of Cost-Effective Natural Gas-Fueled Generation:

In its 2019 Site Plan, FPL's resource plan projected the addition of three new CC units with one each being added in 2019, 2022, and 2026. Gulf's 2019 Site Plan projected the addition of a single new CC unit in 2024.

The first of the three FPL projected CC units was the Okeechobee Clean Energy Center unit which became operational on FPL's system in 2019. This new CC unit supplies approximately 1,778 MW of firm capacity that can be delivered around the clock. The second of these is the previously mentioned Dania Beach CC unit that will come in-service in 2022. This unit is a key component of the modernization of FPL's existing Lauderdale power plant site as discussed above. The third CC projected in FPL's 2019 Site Plan was a new CC unit being added in 2026 at an as-yet-to-be-determined site. Gulf's 2019 Site Plan projected a single new CC unit to be added at its Escambia site in 2024.

The resource plan presented in this 2020 Site Plan continues to show the new Dania Beach CC unit coming in-service in 2022. However, neither the other CC unit previously projected in FPL's area for 2026, nor the Escambia CC unit in Gulf's area previously projected for 2024, remain in the current resource plan. However, four new CT units at the existing Crist plant site in Gulf's area are now part of the resource plan. These new CT units are being added based on system economics and for purposes of ensuring adequate fast-start operating reserves in Gulf's area.

Nuclear energy:

Nuclear energy remains an important factor in FPL's resource planning. Since June 2009, FPL has worked to secure from the federal Nuclear Regulatory Commission (NRC) Combined Operating Licenses (COL) for two future nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (the location of two existing nuclear generating units). In April 2018, FPL received NRC approval for these two COLs. These licenses remain valid for approximately 20 years. At this time, FPL has paused regarding a decision whether to seek FPSC approval to move forward with construction of the new nuclear units. FPL intends to incorporate into that decision the construction experience of the nuclear units currently under construction by Georgia Power at its Vogtle site and similar units being developed in China. As a result, and similar to the case with FPL's 2019 Site Plan, the earliest possible in-service dates for Turkey Point 6 & 7 are beyond the 10-year time period addressed in this 2020 Site Plan.

In addition, on January 30, 2018, FPL applied to the NRC for Subsequent License Renewal (SLR) for FPL's existing Turkey Point Units 3 & 4. The previous license terms for these two existing nuclear units extended into the years 2032 and 2033, respectively. The SLR requested approval to extend the operating licenses by 20 years to 2052 and 2053, respectively. The NRC granted approval for the SLR in December 2019. Consequently, FPL's resource plans include the continued operation of Turkey Point Units 3 & 4 out in time to those new license termination dates.

For these reasons, this Site Plan continues to present the Turkey Point location as a Preferred Site for nuclear generation as indicated in Chapter III.

II. Other Factors That Have Influenced, or Could Further Influence, the Current Resource Plan:

There are a number of factors that have influenced, or which may influence, the resource plan presented in this 2020 Site Plan. Six such factors are summarized below and are presented in no particular order. These factors and/or their potential influences on the resource plan presented in this Site Plan are further discussed in Chapters II and III.

<u>Factor # 1: The critical need to maintain a balance between load and generating capacity in Southeastern Florida (Miami-Dade and Broward counties).</u> This balance has both reliability and economic implications for FPL's system and customers and it is a key reason that FPL sought and obtained an affirmative need determination decision from the FPSC for the Lauderdale modernization described above.

<u>Factor # 2: The desire to maintain/enhance fuel diversity in the FPL system while considering system economics.</u> Diversity is sought in terms of the types of fuel that FPL utilizes and how these fuels are transported to the locations of FPL's generation units. These fuel diversity objectives are considered in light of economic impacts to FPL's customers. For example, FPL is cost-effectively adding significant amounts of PV generation throughout the 10-year reporting period of this document. These PV additions enhance fuel diversity. At the same time, FPL is retiring coal generation and older, fuel-inefficient oil- or gas-fueled generation because these generating units are no longer cost-effective for FPL's customers. In addition, FPL also seeks to further enhance the efficiency with which it uses natural gas to generate electricity.

<u>Factor # 3: The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations.</u> FPL addresses this through the use of a 10% generation-only reserve margin (GRM) reliability criterion to complement its other two reliability criteria:

a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability and operations in a comprehensive manner.

Factor # 4: The significant impact of federal and state energy-efficiency codes and standards. The incremental impacts of these energy-efficiency codes and standards, from a beginning year 2020 starting point through the year 2029, are projected to have significant impacts by reducing forecasted Summer and Winter peak loads, and by reducing annual net energy for load (NEL), in both the FPL and Gulf areas. In addition, energy-efficiency codes and standards significantly reduce the potential for cost-effective energy efficiency that might otherwise have been obtained through utility DSM programs. The projected impacts of these energy efficiency codes and standards are discussed in more detail in Chapter II.

Factor # 5: The trends of decreasing costs for fuel, decreasing costs for new generating units, and increasing fuel efficiency of new generating units. There are a number of factors that drive utility system costs. Three of the most important of these are: (i) forecasted natural gas costs, (ii) projected costs for new generating units, and (iii) the efficiency with which generating units convert fuel into electricity. When comparing FPL's forecasts of these factors over at least the last 5 years, the trends for each of these factors is in a direction that results in lower system costs for FPL's customers. For example, when comparing FPL's 2015 forecasted cost for natural gas for the year 2020 with the current (2020) forecasted cost for 2020, there has been more than a 55% decrease in natural gas costs. An even greater reduction in CO_2 compliance costs for 2020 occurred between the 2015 and current forecast. In addition, in regard to the fuel efficiency of FPL's generating units, the amount of natural gas (measured in mmBTU of natural gas needed to produce a kWh of electricity) declined from 7,376 in 2015 to approximately 6,752 today. This improvement in fuel efficiency is truly significant, especially when considering the approximately 20,000 MW of gas-fueled generation on FPL's system.

These trends of steadily lowering of key components of utility system costs are very beneficial to a utility's customers because they help to lower electric rates.[5]

Factor # 6: Projected changes in CO_2 regulation and associated compliance costs. Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has included projected compliance costs for CO_2 emissions in its resource planning work. However, there always has been an unavoidable level of uncertainty regarding the timing and magnitude of the cost impacts of the potential regulation/legislation. The forecast of potential CO_2 compliance costs that FPL used in its 2019 resource

[5] However, because the potential benefits of utility DSM programs are based on DSM's ability to avoid certain system costs, the trend of steadily decreasing utility system costs automatically results in a significant lowering of the cost-effectiveness of utility DSM programs.

planning work was lower than forecasts that had been used in prior years. In 2020, the forecasted compliance costs are somewhat higher than projected in 2019, but remain lower than projections from a decade before. Projected lower compliance costs are due to a number of factors projected for the Southeastern region of the U.S., including Florida. These factors include at least the following: lower forecasted growth rates in electricity usage; lower forecasted costs of natural gas; retirements of existing coal units; and increasing implementation of renewable energy sources including solar.

Each of these factors will continue to be examined by FPL's resource planning group in its ongoing resource planning work in 2020 and future years.

III. A Summary of Projected Resource Changes for FPL and Gulf:

The resource plan presented in this 2020 Site Plan was developed based on considerations of projected system reliability, projected system economics, and other factors such as those discussed immediately above. Major changes in resources currently projected as part of this resource plan for the years 2020 through 2029 for both FPL and Gulf are summarized in Table ES-1. The changes are presented in terms of Summer firm capacity values.

Although this particular table does not specifically identify the impacts of projected DSM on resource needs and the resource plan, the projected DSM additions reflected in the resource plan presented in Table ES-1, and throughout this Site Plan, are consistent with the 2020 through 2024 DSM Goals set for FPL and Gulf (Order No. PSC-2019-0509-FOF-EG) in 2019 by the FPSC. The specific impacts of those DSM Goals through 2024, and of projected additional DSM impacts for 2025 through 2029, are shown in Schedules 3.1, 3.2, and 3.3.

A summary of some of the larger resource additions/retirements for both systems/areas include, but are not necessarily limited to, those listed below (in approximate chronological order):

<u>For FPL's system/area:</u>

- New solar (PV) additions from 2020 through 2029 of approximately 7,300 MW;
- Capacity upgrades at a number of FPL's existing CC units through 2026;
- Retirement of FPL's ownership portion (approximately 630 MW) of the Scherer 4 coal unit by January 2022;
- A 409 MW battery storage facility at the Manatee plant site, plus two 30 MW battery storage facilities at different sites, by the beginning of 2022; and,
- The modernization of the existing Lauderdale power plant site in mid-2022 with the new DBEC CC Unit 7.

For Gulf's system/area:

- New solar (PV) additions from 2020 through 2024 of approximately 1,560 MW;
- Capacity upgrades (two) of the existing Lansing Smith Unit 3 CC, with installation for the first upgrade completed in 2019 with testing and tuning in the Spring of 2020, then a planned second upgrade in 2024;
- Conversion from coal-fueled to natural gas-fueled of Crist Units 6 & 7 in 2020;
- A new FPL-to-Gulf transmission line by the beginning of 2022 enabling a bidirectional transfer capability between the two areas of 850 MW;
- Four new CTs at the Crist plant site by the beginning of 2022
- Expiration (as per the contract) of 885 MW from the Shell PPA in May, 2023;
- The retirement of Gulf's ownership portion of the coal-fueled Daniels Units 1 & 2 by the beginning of 2024; and,
- A total of approximately 700 MW of battery storage in 2028 and 2029.

It is noted that no final decisions are needed at this time, nor have such decisions yet been made, regarding some of the resource additions shown in this 2020 Site Plan. This is particularly relevant to resource additions shown for years increasingly further out in time in the 2020 through 2029 time period. Consequently, those resource additions are more prone to future change.

Table ES-1: Projected Capacity & Firm Purchase Power Additions and Changes:

Year [1/]	Projected Capacity & Firm Purchase Power Changes	FPL Summer MW (Approx.)	Gulf Summer MW (Approx.)	Date	Summer Reserve Margin [2/]
	FPL				
2020	Solar PV [3/] (All solar facilities in-service January of 2020)	248		First Quarter 2020	
	SoBRA PV [3/]	165		Second Quarter 2020	
	Sanford 4	147		Second Quarter 2020	
	Total of MW changes to Summer firm capacity:	**560**			**21.2%**
2021	West County 3	21		Third Quarter 2020	
	Turkey Point 4	20		Fourth Quarter 2020	
	Solar PV [3/]	539		First Quarter 2021	
	Solar Degradation [4/]	(3)			
	Total of MW changes to Summer firm capacity:	**577**			**21.6%**
	Gulf				
2020	Solar PV [3/] (Solar facility in-service April 1st of 2020)		41	Fourth Quarter 2020	
	Total of MW changes to Summer firm capacity:		**41**		**39.5%**
2021					
	Total of MW changes to Summer firm capacity:		**0**		**38.1%**
	Integrated FPL and Gulf				
2022	Manatee 1 and 2 Retirement	(1,618)		Fourth Quarter 2021	
	Scherer 4 Retirement	(634)		Fourth Quarter 2021	
	Manatee Energy Storage	409		Fourth Quarter 2021	
	Sunshine Gateway Energy Storage	30		Fourth Quarter 2021	
	Echo River Energy Storage	30		Fourth Quarter 2021	
	4X0 Crist CT's		938	Fourth Quarter 2021	
	Blue Springs PV [3/]		37	Fourth Quarter 2021	
	Chautauqua PV [3/]		37	Fourth Quarter 2021	
	Solar PV [3/]		224	First Quarter 2022	
	Fort Myers 2 Upgrade	40		Second Quarter 2022	
	Dania Beach Clean Energy Center Unit 7	1,163		Second Quarter 2022	
	Solar Degradation [4/]	(5)			
	Total of MW changes to Summer firm capacity:	**(585)**	**1,237**		**26.1%**
2023	Martin 8 Upgrade	40		Second Quarter 2022	
	Manatee 3 Upgrade	79		Fourth Quarter 2022	
	Solar PV [3/]		209	First Quarter 2023	
	Fort Myers 2 Upgrade	79		Second Quarter 2023	
	Solar Degradation [4/]	(6)			
	Total of MW changes to Summer firm capacity:	**192**	**209**		**22.8%**
2024	Lansing Smith 3 Upgrade		59	Fourth Quarter 2023	
	Daniel 1 and 2 Retirement		(502)	First Quarter 2024	
	Turkey Point 5 Upgrade	79		First Quarter 2024	
	Okeechobee Energy Center	58		First Quarter 2024	
	Solar PV [3/]		209	First Quarter 2024	
	Solar Degradation [4/]	(6)			
	Total of MW changes to Summer firm capacity:	**131**	**(234)**		**20.8%**
2025	Pea Ridge 1, 2 and 3 Retirement		(12)	Second Quarter 2024	
	Crist 4 Retirement		(75)	Fourth Quarter 2024	
	Solar PV [3/]	264		First Quarter 2025	
	Sanford 4 Upgrade	78		Second Quarter 2025	
	Sanford 5 Upgrade	78		Second Quarter 2025	
	Solar Degradation [4/]	(7)			
	Total of MW changes to Summer firm capacity:	**413**	**(87)**		**20.5%**
2026	Martin 8 Upgrade	40		Second Quarter 2025	
	Sanford 4 Upgrade	26		Second Quarter 2025	
	Sanford 5 Upgrade	26		Second Quarter 2025	
	Solar PV [3/]	422		First Quarter 2026	
	Solar Degradation [4/]	(8)			
	Total of MW changes to Summer firm capacity:	**506**			**20.6%**
2027	Crist 5 Retirement		(75)	Fourth Quarter 2026	
	Solar PV [3/]	422		First Quarter 2027	
	Solar Degradation [4/]	(9)			
	Total of MW changes to Summer firm capacity:	**413**	**(75)**		**20.3%**
2028	Lansing Smith A Retirement		(32)	Fourth Quarter 2027	
	Energy Storage		200	First Quarter 2028	
	Solar PV [3/]	252		First Quarter 2028	
	Solar Degradation [4/]	(11)			
	Total of MW changes to Summer firm capacity:	**241**	**168**		**20.0%**
2029	Energy Storage		500	First Quarter 2029	
	Solar PV [3/]	194		First Quarter 2029	
	Solar Degradation [4/]	(11)			
	Total of MW changes to Summer firm capacity:	**183**	**500**		**20.0%**

1/ Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.
2/ Winter Reserve Margins are typically higher than Summer Reserve Margins. Winter Reserve Margins are shown on Schedule 7.2 in Chapter III.
3/ MW values shown for the PV facilities represent the summer firm capacity assumptions for the PV facilities.
4/ An annual 0.3% degradation for PV output is assumed for both FPL and Gulf Solar. Total degradation is shown solely in the FPL column.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

I.A. FPL System:

I.A.1 Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately ten million people. FPL served an average of 5,061,525 customer accounts in 35 counties during 2019. These customers were served by a variety of resources including: FPL-owned fossil-fuel, renewable (solar), and nuclear generating units; non-utility owned generation; demand side management (DSM); and interchange/purchased power.

I.A.2 FPL - Owned Resources

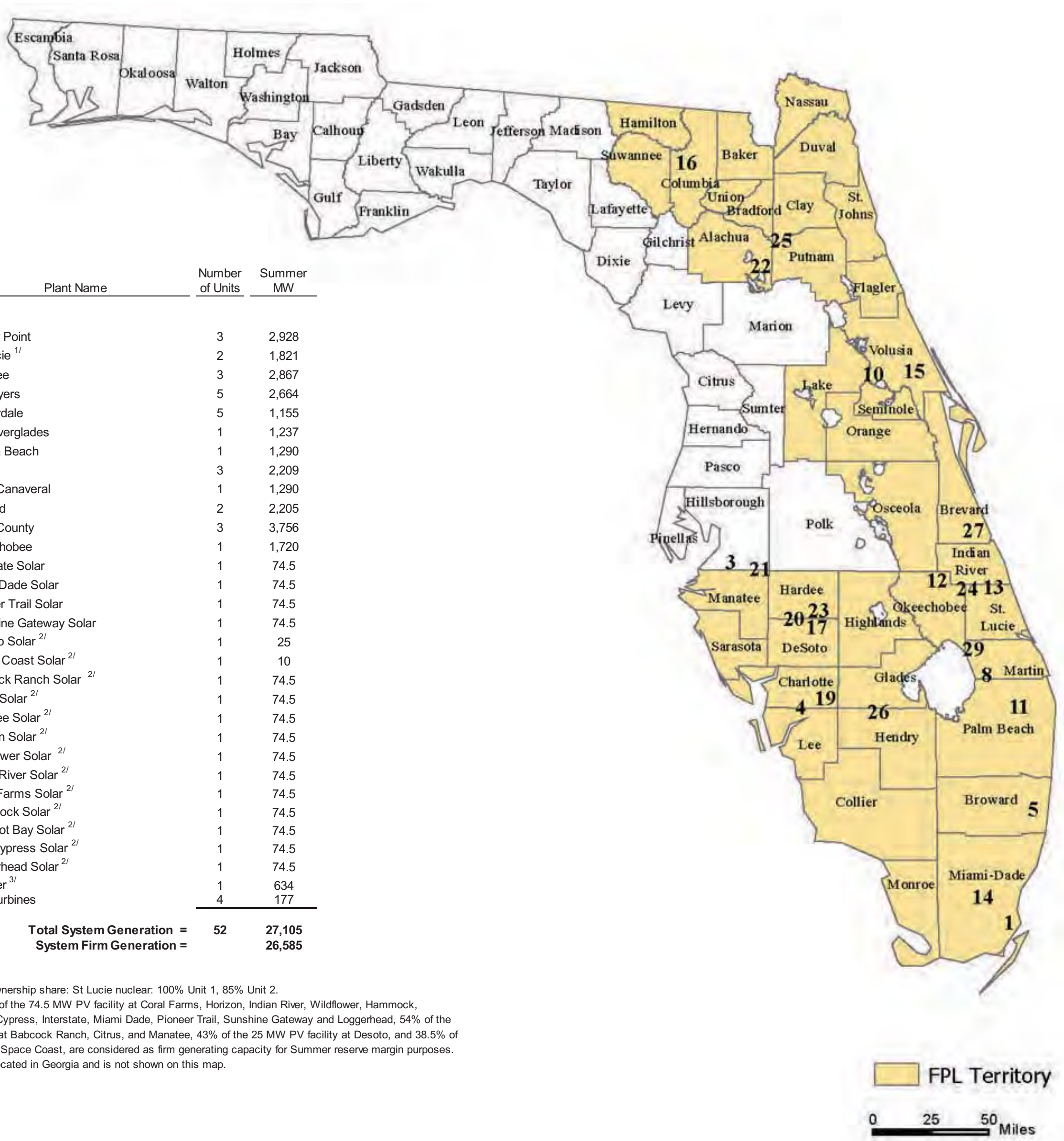
As of December 31, 2019, FPL owned electric generating resources located at 29 sites distributed geographically throughout its service territory, plus one site in Georgia (partial FPL ownership of one unit). These generating facilities consisted of: four nuclear units, one coal unit (the aforementioned partially owned unit), 15 combined-cycle (CC) units, two fossil steam units, four gas turbines (GTs), nine simple-cycle combustion turbines (CTs), and 17 solar photovoltaic (PV) facilities.[6] The locations of the 52 generating units that were in commercial operation on December 31, 2019 are shown on Figure I.A.2.1 and in Table I.A.2.1.

FPL's bulk transmission system, including both overhead and underground lines, is comprised of 7,278 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through FPL's 661 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.2.

[6] FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location



Location/ Map Key	Plant Name	Number of Units	Summer MW
1	Turkey Point	3	2,928
2	St. Lucie [1/]	2	1,821
3	Manatee	3	2,867
4	Fort Myers	5	2,664
5	Lauderdale	5	1,155
6	Port Everglades	1	1,237
7	Riviera Beach	1	1,290
8	Martin	3	2,209
9	Cape Canaveral	1	1,290
10	Sanford	2	2,205
11	West County	3	3,756
12	Okeechobee	1	1,720
13	Interstate Solar	1	74.5
14	Miami Dade Solar	1	74.5
15	Pioneer Trail Solar	1	74.5
16	Sunshine Gateway Solar	1	74.5
17	DeSoto Solar [2/]	1	25
18	Space Coast Solar [2/]	1	10
19	Babcock Ranch Solar [2/]	1	74.5
20	Citrus Solar [2/]	1	74.5
21	Manatee Solar [2/]	1	74.5
22	Horizon Solar [2/]	1	74.5
23	Wildflower Solar [2/]	1	74.5
24	Indian River Solar [2/]	1	74.5
25	Coral Farms Solar [2/]	1	74.5
26	Hammock Solar [2/]	1	74.5
27	Barefoot Bay Solar [2/]	1	74.5
28	Blue Cypress Solar [2/]	1	74.5
29	Loggerhead Solar [2/]	1	74.5
	Scherer [3/]	1	634
	Gas Turbines	4	177
	Total System Generation =	**52**	**27,105**
	System Firm Generation =		**26,585**

1/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2.
2/ Approximately 56% of the 74.5 MW PV facility at Coral Farms, Horizon, Indian River, Wildflower, Hammock, Barefoot Bay, Blue Cypress, Interstate, Miami Dade, Pioneer Trail, Sunshine Gateway and Loggerhead, 54% of the 74.5 MW PV facility at Babcock Ranch, Citrus, and Manatee, 43% of the 25 MW PV facility at Desoto, and 38.5% of the 10 MW of PV at Space Coast, are considered as firm generating capacity for Summer reserve margin purposes.
3/ The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.2.1: FPL's Generating Resources by Location (as of December 31, 2019)

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2019)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie [1/]	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,658
Total Nuclear:		**4**		**3,479**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	634
Total Coal Steam:		**1**		**634**
Combined-Cycle				
Fort Myers	Fort Myers, FL	1	Gas	1,812
Manatee	Manatee County, FL	1	Gas	1,249
Martin	Indiantown, FL	2	Gas	974
Sanford	Lake Monroe, FL	2	Gas	2,205
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,290
Martin	Indiantown, FL	1	Gas/Oil	1,235
Okeechobee	Okeechobee, FL	1	Gas/Oil	1,720
Port Everglades	City of Hollywood, FL	1	Gas/Oil	1,237
Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,290
Turkey Point	Florida City, FL	1	Gas/Oil	1,270
West County	Palm Beach County, FL	3	Gas/Oil	3,756
Total Combined Cycle:		**15**		**18,038**
Gas/Oil Steam				
Manatee	Manatee County, FL	2	Gas/Oil	1,618
Total Oil/Gas Steam:		**2**		**1,618**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	2	Oil	108
Lauderdale (GT)	Dania, FL	2	Gas/Oil	69
Total Gas Turbines/Diesels:		**4**		**177**
Combustion Turbines				
Lauderdale	Dania, FL	5	Gas/Oil	1,155
Fort Myers	Fort Myers, FL	4	Gas/Oil	852
Total Combustion Turbines:		**9**		**2,007**
PV [2/]				
DeSoto Solar	DeSoto County, FL	1	Solar Energy	25
Babcock Ranch Solar	Charlotte County, FL	1	Solar Energy	74.5
Citrus Solar	DeSoto County, FL	1	Solar Energy	74.5
Manatee Solar	Manatee County, FL	1	Solar Energy	74.5
Space Coast Solar	Brevard County, FL	1	Solar Energy	10
Interstate Solar	St. Lucie County, FL	1	Solar Energy	74.5
Miami Dade Solar	Dade County, FL	1	Solar Energy	74.5
Pioneer Trail Solar	Volusia County, FL	1	Solar Energy	74.5
Sunshine Gateway Solar	Columbia County, FL	1	Solar Energy	74.5
Horizon Solar	Putnam and Alachua Counties, FL	1	Solar Energy	74.5
Wildflower Solar	Desoto County, FL	1	Solar Energy	74.5
Indian River Solar	Indian River County, FL	1	Solar Energy	74.5
Coral Farms Solar	Putnam County, FL	1	Solar Energy	74.5
Hammock Solar	Hendry County, FL	1	Solar Energy	74.5
Barefoot Bay Solar	Brevard County, FL	1	Solar Energy	74.5
Blue Cypress Solar	Indian River County, FL	1	Solar Energy	74.5
Loggerhead Solar	St. Lucie County, FL	1	Solar Energy	74.5
Total PV:		**17**		**1,153**
Total System Generation as of December 31, 2019 =		**52**		**27,105**
System Firm Generation as of December 31, 2019 =				**26,585**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Approximately 56% of the 74.5 MW PV facility at Coral Farms, Horizon, Indian River, Wildflower, Hammock, Barefoot Bay, Blue Cypress, Interstate, Miami Dade, Pioneer Trail, Sunshine Gateway and Loggerhead, 54% of the 74.5 MW PV facility at Babcock Ranch, Citrus, and Manatee, 43% of the 25 MW PV facility at Desoto, and 38.5% of the 10 MW of PV at Space Coast, are considered as firm generating capacity for Summer reserve margin purposes.

FPL Bulk Transmission System

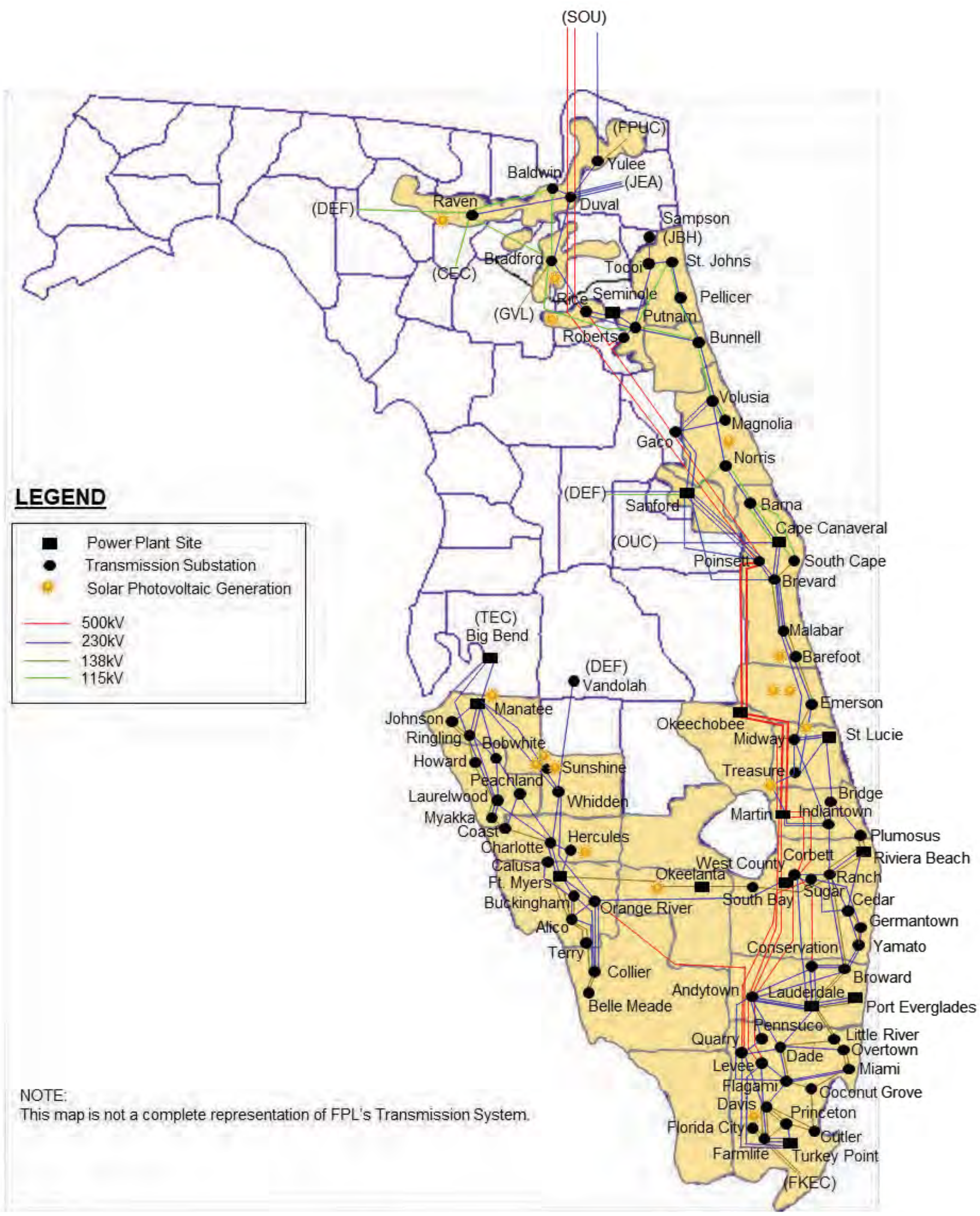


Figure I.A.2.2: FPL Bulk Transmission System

I.A.3 FPL - Capacity and Energy Power Purchases

Firm Capacity: Purchases from Qualifying Facilities (QF)

Firm capacity power purchases remain part of FPL's resource mix. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (*e.g.*, steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses solar, wind, waste, geothermal, or other renewable resources as its primary energy source.

FPL currently has four contracts with qualifying facilities (*e.g.*, cogeneration/small power production facilities) to purchase firm capacity and energy during the 10-year reporting period of this Site Plan. The 2019 actual and 2020-2029 projected contributions from these facilities are shown in Table I.A.3.1, Table I.A.3.2, and Table I.A.3.3. As discussed in prior FPL Site Plans, the FPSC approved (Order No. PSC-16-0506-FOF-EI) FPL's acquisition of the rights to the 330 MW Indiantown Cogen LP (ICL) unit and the associated power purchase agreement (PPA). FPL currently projects that it will cancel this PPA by the end of the 4th Quarter of 2020 because the agreement is no longer cost-effective for FPL's customers.

Firm Capacity: Purchases from Utilities

FPL currently has a PPA with Orlando Utilities Commission. Information regarding this PPA is shown in Table I.A.3.2 and Table I.A.3.3.

Firm Capacity: Other Purchases

FPL has two other firm capacity purchase contracts with the Palm Beach Solid Waste Authority. Table I.A.3.2 and I.A.3.3 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from a number of cogeneration and small power production facilities. The lower half of Table I.A.3.1 shows the amount of energy purchased in 2019 from these facilities.

Table I.A.3.1: FPL's Purchased Power Resources by Contract (as of December 31, 2019)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
Indiantown Cogen LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
		Total:	334
II. Purchases from Utilities & IPP			
Palm Beach SWA - extension	Palm Beach	Solid Waste	40
Palm Beach SWA - New Unit	Palm Beach	Solid Waste	70
OUC/FMPA	Orange	Gas	100
		Total:	210
	Total Net Firm Generating Capability:		544

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2019
Miami Dade Resource Recovery 1/	Dade	Solid Waste	55,702
Broward South 1/	Broward	Solid Waste	48,779
Lee County Solid Waste 1/	Lee	Solid Waste	45,916
Brevard County 1/	Brevard	Solid Waste	38,226
Okeelanta (known as Florida Crystals and New Hope Power Partners) 1/	Palm Beach	Bagasse/Wood	36,052
Waste Management - Collier County Landfill 1/	Collier	Landfill Gas	25,527
Landfill Energy Systems (Aria Energy) 1/	Seminole	Landfill Gas	15,058
Tropicana	Manatee	Natural Gas	6,056
Georgia Pacific	Putnam	Paper by-product	4,437
Landfill Energy Systems (Aria Energy) 1/	Sarasota	Landfill Gas	2,062
Waste Management Renewable Energy 1/	Broward	Landfill Gas	1,520
Fortistar - Port Charlotte 1/	Charlotte	Landfill Gas	361
Customer Owned PV & Wind	Various	PV/Wind	72,084

1/ These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 9, column 6.

Table I.A.3.2: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities [1/]	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0	0
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0	0
Indiantown Cogen L.P.	12/22/95	4th Qtr/2020	330	0	0	0	0	0	0	0	0	0
		QF Purchases Subtotal:	**334**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OUC	10/01/18	12/31/20	100	0	0	0	0	0	0	0	0	0
		Utility Purchases Subtotal:	**100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total of QF and Utility Purchases =	**434**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Palm Beach SWA - Extension [2/]	01/01/12	04/01/34	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	01/01/15	04/01/34	70	70	70	70	70	70	70	70	70	70
		Other Purchases Subtotal:	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total "Non-QF" Purchases =	**210**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Summer Firm Capacity Purchases Total MW:	**544**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**110**	**110**

1/ The Indiantown Cogen L.P. PPA is projected to end, and the generating unit to be retired, in 4th Quarter 2020.
2/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and it then became accounted for under "Other Purchases"

Table I.A.3.3: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities 1/	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0	0	0
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0	0	0
Indiantown Cogen L.P.	12/22/95	4th Qtr/2020	330	0	0	0	0	0	0	0	0	0
QF Purchases Subtotal:			**334**	**4**	**4**	**4**	**4**	**4**	**4**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OUC	10/01/18	12/31/20	70	0	0	0	0	0	0	0	0	0
Utility Purchases Subtotal:			**70**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total of QF and Utility Purchases =	**404**	**4**	**4**	**4**	**4**	**4**	**4**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Palm Beach SWA - Extension 2/	01/01/12	04/01/34	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	01/01/15	04/01/34	70	70	70	70	70	70	70	70	70	70
Other Purchases Subtotal:			**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

Total "Non-QF" Purchases =	**180**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Winter Firm Capacity Purchases Total MW:	**514**	**114**	**114**	**114**	**114**	**114**	**114**	**110**	**110**	**110**

1/ The Indiantown Cogen L.P. PPA is projected to end, and the generating unit to be retired, in 4th Quarter 2020.
2/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and it then became accounted for under "Other Purchases"

I.A.4 FPL - Demand Side Management (DSM)

FPL has continually explored and implemented cost-effective DSM programs since 1978, and it has consistently been among the leading utilities nationally in achieving substantial DSM efficiencies. These programs include a number of innovative conservation/energy efficiency and load management initiatives. Importantly, FPL's DSM efforts through 2019 have resulted in a cumulative Summer peak reduction of 4,870 MW at the generator and an estimated cumulative energy savings of 89,166 Gigawatt-Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirements, FPL's highly effective DSM efforts through 2019 have eliminated the need to construct the equivalent of approximately fifteen (15) new 400 MW generating units. Also, it is important to note that FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In 2019, the Florida Public Service Commission (FPSC) set DSM Goals for the years 2020 through 2024 for FPL and the other Florida utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). For these 5 years, these Goals are identical to the Goals set by the FPSC in 2014 for the years 2020 through 2024. In February 2020, FPL filed for FPSC approval its DSM Plan with which it intends to meet the DSM Goals. In this Site Plan, FPL assumes that the annual reduction values for Summer MW, Winter MW, and energy (MWh) set forth in the DSM Goals order (Order No. PSC-2019-0509-FOF-EG) will be met as shown in various schedules presented in this Site Plan. For the years 2025 through 2029, for which the FPSC did not establish Goals, FPL has assumed that DSM will be implemented to achieve the DSM levels that FPL proposed in its 2019 DSM Goals filing because this level of annual DSM was projected to be cost-effective.

Florida Power & Light Company
Gulf Power Company
Docket No. 20200000-OT
Staff's First Data Request
Request No. 1
Attachment No. 1
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Schedule 1

FPL Existing Generating Facilities
As of December 31, 2019

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Babcock Ranch Solar [2/]		Charlotte County											
		29,31,32/41S/26E : 5,6/42S/26E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5
Barefoot Solar [2/]		Brevard County											
		15,16/30S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Blue Cypress Solar [2/]		Indian River County											
		16,21/33S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Cape Canaveral		Brevard County											
		19/23S/36E									1,295,400	1,393	1,290
	3		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,393	1,290
Citrus Solar [2/]		DeSoto County											
		26,27,34,35,36/36S/25E : 1,2/37S/25E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5
Coral Farms Solar [2/]		Putnam County											
		27,28,33,34/8S/24E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
DeSoto Solar [2/]		DeSoto County											
		27,28/36S/25E									22,500	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	22,500	25	25
Fort Myers		Lee County											
		35/43S/25E									2,796,198	2,750	2,772
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,836,798	1,787	1,812
	3		CT	NG	FO2	TK	TK	Unknown	Jun-03	Unknown	835,380	840	852
	1, 9		GT	FO2	No	WA	No	Unknown	May-74	Unknown	124,020	123	108
Hammock Solar [2/]		Hendry County											
		33,34/43S/30E : 3,4,9,10/44S/30E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Horizon Solar [2/]		Alachua County											
		25,35,36/9S/22E : 30, 31/9S/23E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
Indian River Solar [2/]		Indian River County											
		30,31/33S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
Interstate Solar [2/]		St. Lucie County											
		28,29,33/34S/39E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5
Lauderdale		Broward County											
		30/50S/42E									1,215,956	1,184	1,224
	6		CT	NG	FO2	PL	TK	Unknown	Dec-16	Unknown	1,147,500	1,110	1,155
	3, 5		GT	NG	FO2	PL	TK	Unknown	Aug-70	Unknown	68,456	74	69
Loggerhead Solar [2/]		St. Lucie County											
		21,28,33/37S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Manatee Solar [2/]		Manatee County											
		1,12,13,24/33S/19E : 6,7,18,19/33S/20E									6,130,464	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5
Manatee		Manatee County											
		18/33S/20E									3,027,982	2,903	2,867
	1		ST	NG	FO6	PL	WA	Unknown	Oct-76	4th Qtr/2021	863,300	819	809
	2		ST	NG	FO6	PL	WA	Unknown	Dec-77	4th Qtr/2021	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,301,382	1,265	1,249

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ Approximately 56% of the 74.5 MW PV facility at Coral Farms, Horizon, Indian River, Interstate, Hammock, Barefoot Bay, Blue Cypress, and Loggerhead, 54% of the 74.5 MW PV Facility at Babcock Ranch, Citrus, and Manatee and 43% of the 25 MW PV facility at Desoto is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel Transport		Alt. Fuel Days	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1/]	
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Pri.	Alt.	Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW
Martin		Martin County											
		30/39S/38E									2,525,382	2,337	2,209
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	533	487
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	533	487
	8 [4/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,301,382	1,271	1,235
Miami Dade Solar [3/]		Dade County											
		13,24/55S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Okeechobee		Okeechobee											
		2/33S/35E									1,886,150	1,672	1,720
	1		CC	NG	FO2	PL	TK	Unknown	Mar-19	Unknown	1,886,150	1,672	1,720
Pioneer Trail Solar [3/]		Volusia County											
		16,20,21,28,29,32/17S/32E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Port Everglades		City of Hollywood											
		23/50S/42E									1,412,700	1,338	1,237
	5		CC	NG	FO2	PL	TK	Unknown	Apr-16	Unknown	1,412,700	1,338	1,237
Riviera Beach		City of Riviera Beach											
		33/42S/432E									1,295,400	1,393	1,290
	5		CC	NG	FO2	PL	TK	Unknown	Apr-14	Unknown	1,295,400	1,393	1,290
Sanford		Volusia County											
		16/19S/30E									2,531,464	2,335	2,205
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,265,732	1,147	1,029
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,265,732	1,188	1,176
Scherer [2/]		Monroe, GA									680,368	635	634
	4		ST	SUB	No	RR	No	Unknown	Jul-89	4th Q 2021	680,368	635	634
Space Coast Solar [3/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Lucie [5/]		St. Lucie County											
		16/36S/41E									1,999,128	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,080,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	919,128	860	840
Sunshine Gateway Solar [3/]		Columbia County											
		25.26,35,36/2S/15E : 31/2S/16E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Turkey Point		Miami Dade County											
		27/57S/40E									3,055,782	3,018	2,928
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	859	837
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,301,382	1,311	1,270
West County		Palm Beach County											
		29/43S/40E									4,100,400	4,087	3,756
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,369	1,259
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,369	1,259
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,349	1,238
Wildflower Solar [3/]		Desoto County											
		25,26,35,36/36S/25E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
										Total System Generating Capacity as of December 31, 2019 [6/] =		**28,061**	**27,105**
										System Firm Generating Capacity as of December 31, 2019 [7/] =		**26,908**	**26,585**

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These ratings relate to FPL's 76.36% share of Plant Scherer Unit 4 operated by Georgia Power, and represent FPL's 73.923% ownership share available at point of interchange.
3/ Approximately 56% of the 74.5 MW PV facility at Miami Dade, Pioneer Trail, Sunshine Gateway and Wildflower, 38.5% of the 10 MW PV facility at Space Coast is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.
4/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.
5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.
6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

I.B. Gulf System:

I.B.1 Description of Existing Resources

Gulf's service area contains approximately 7,550 square miles and has a population of approximately one million people. Gulf Power served an average of 468,282 customer accounts in 8 counties during 2019. These customers were served by a variety of resources including: Gulf Power-owned fossil-fuel, renewable (solar and wind), other non-utility owned generation; demand side management (DSM); and interchange/purchased power.

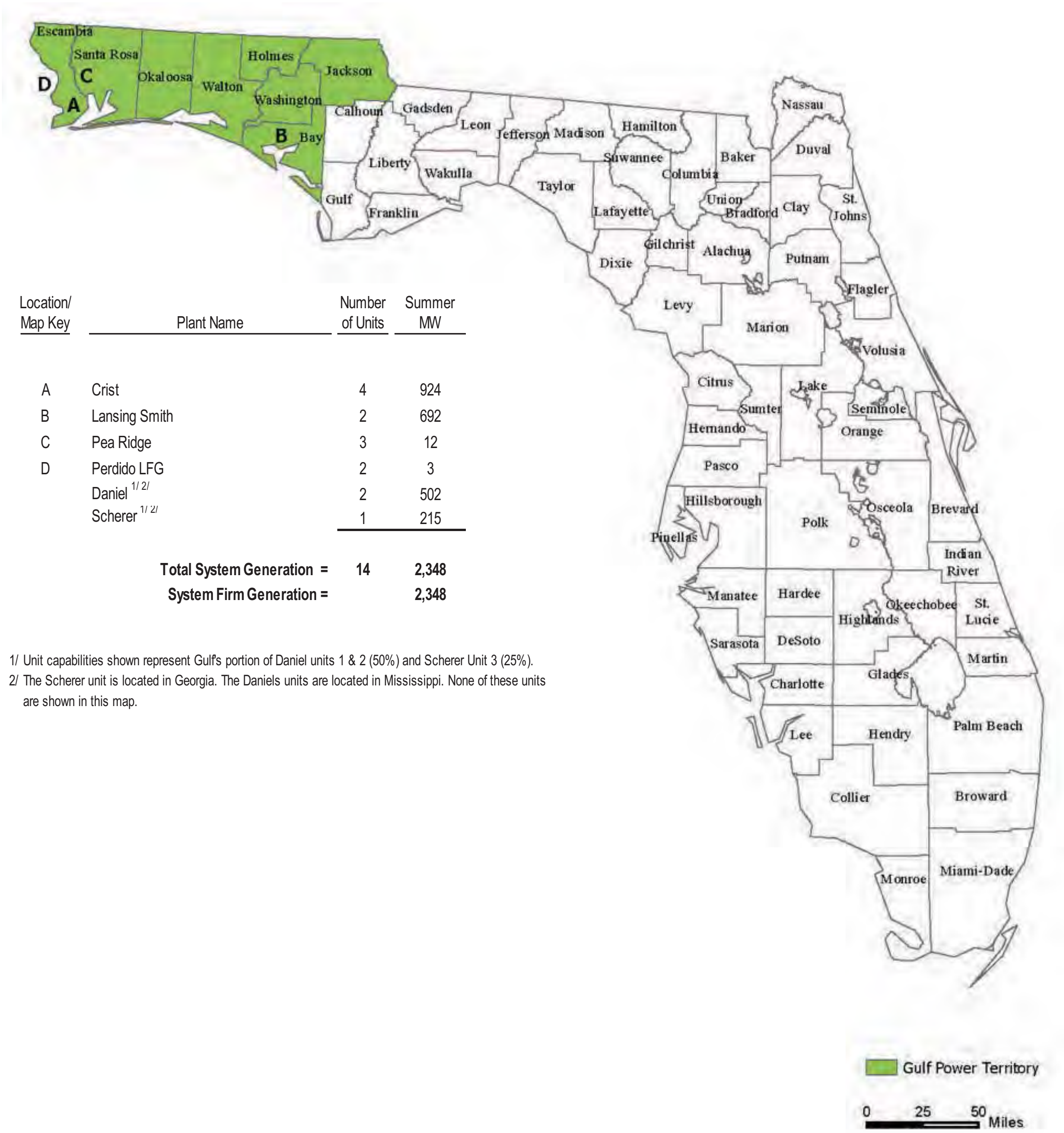
I.B.2 Gulf - Owned Resources

As of December 31, 2019, Gulf owned electric generating resources located at five sites distributed geographically throughout its service territory, plus one site in Georgia (partial Gulf ownership of one unit). These generating facilities consisted of: seven coal units, one combined-cycle (CC) unit, four simple-cycle combustion turbines (CTs), and two landfill gas (LFG) facilities. The locations of the 14 generating units that were in commercial operation on December 31, 2019 are shown on Figure I.B.2.1 and in Table I.B.2.1.

Gulf's bulk transmission system, including both overhead and underground lines, is comprised of 1,672 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through Gulf's 132 substations in Florida.

The existing Gulf system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.B.2.2.

Gulf Power Generating Resources by Location



Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Crist	4	924
B	Lansing Smith	2	692
C	Pea Ridge	3	12
D	Perdido LFG	2	3
	Daniel [1/ 2/]	2	502
	Scherer [1/ 2/]	1	215
	Total System Generation =	**14**	**2,348**
	System Firm Generation =		**2,348**

1/ Unit capabilities shown represent Gulf's portion of Daniel units 1 & 2 (50%) and Scherer Unit 3 (25%).
2/ The Scherer unit is located in Georgia. The Daniels units are located in Mississippi. None of these units are shown in this map.

Figure I.B.2.1: Gulf Power Generating Resources by Location (as of December 31, 2019)

Table I.B.2.1: Gulf Power Capacity Resources by Unit Type (as of December 31, 2019)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Coal Steam				
Crist	Escambia County	4	Coal	924
Daniel	Jackson County, MS	2	Coal	502
Scherer	Monroe County, Ga	1	Coal	215
Total Coal Steam:		**7**		**1,641**
Combined-Cycle				
Lansing Smith	Bay County	1	Gas	660
Total Combined Cycle:		**1**		**660**
Combustion Turbines				
Pea Ridge	Santa Rosa County	3	Gas	12
Lansing Smith	Bay County	1	Oil	32
Total Combustion Turbines:		**4**		**44**
Land Fill Gas				
Perdido LFG	Escambia County	2	LFG	3
Total LFG:		**2**		**3**
	Total System Generation as of December 31, 2019 =	**14**		**2,348**
	System Firm Generation as of December 31, 2019 =			**2,348**

Gulf Power Bulk Transmission System

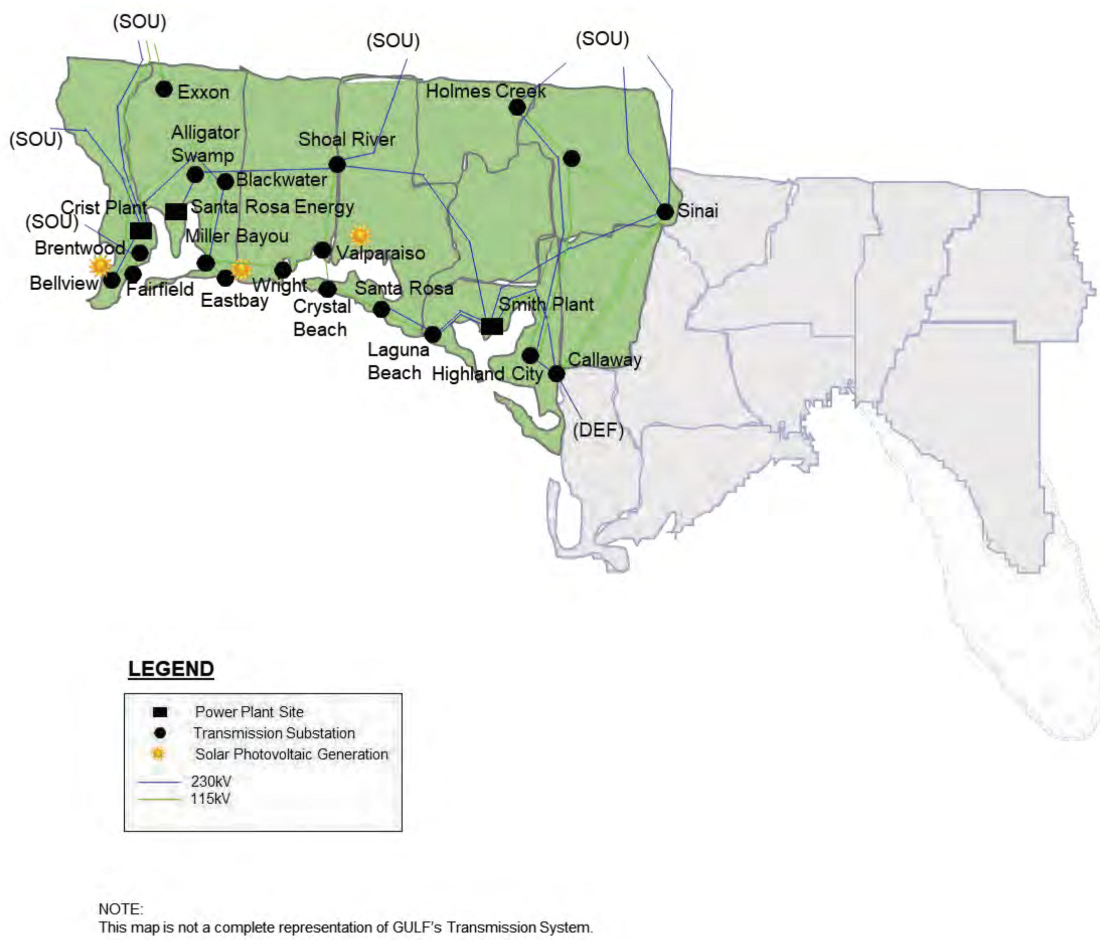


Figure I.B.2.2: Gulf Power Bulk Transmission System

I.B.3 Gulf - Capacity and Energy Power Purchases

Firm Capacity: Purchases from Qualifying Facilities (QF)

Gulf currently has no contracts with qualifying facilities (*e.g.*, cogeneration/small power production facilities) to purchase firm capacity and energy during the 10-year reporting period of this Site Plan.

Firm Capacity: Purchases from Utilities

Gulf currently has no PPAs with other utilities.

Firm Capacity: Other Purchases

Gulf has three firm capacity purchase contracts; two with Morgan Stanley Capital Group's Kingfisher I and Kingfisher II wind projects, and one with Shell Energy North America's Tenaska project. The 2019 actual and 2020-2029 projected contributions from these facilities are shown in Table I.B.3.1, I.B.3.2 and I.B.3.3.

Non-Firm (As Available) Energy Purchases

Gulf purchases non-firm (as-available) energy from a number of cogeneration and small power production facilities. The lower half of Table I.B.3.1 shows the amount of energy purchased in 2019 from these facilities.

Table I.B.3.1: Gulf Power Purchased Power Resources by Contract (as of December 31, 2019)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
		Total:	-
II. Purchases from Utilities & IPP			
MSCG - Kingfisher I 1/	Oklahoma	Wind	53
MSCG - Kingfisher II 1/	Oklahoma	Wind	28
SENA - (Shell)	Alabama	Gas	885
		Total:	966
	Total Net Firm Generating Capability:		966

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2019
International Paper Company Units 1&2 1/	Escambia	Biomass	1,084
Ascend - Solutia Units 1-4	Escambia	Gas	198,163
Gulf Coast Solar Center I	Okaloosa	Sun	59,090
Gulf Coast Solar Center II	Santa Rosa	Sun	78,571
Gulf Coast Solar Center III	Escambia	Sun	94,741
Customer Owned PV & Wind	Various	PV/Wind	6,821

1/ These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 9, column 6.

Table I.B.3.2: Gulf Power Firm Purchased Power Summer MW

Summary of Gulf Power Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
None	-	-	-	-	-	-	-	-	-	-	-	-
QF Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
None	-	-	-	-	-	-	-	-	-	-	-	-
Utility Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total of QF and Utility Purchases =	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MSCG - Kingfisher I	01/01/17	12/31/35	53	53	53	53	53	53	53	53	53	53
MSCG - Kingfisher II	01/01/17	12/31/35	28	28	28	28	28	28	28	28	28	28
SENA - (Shell)	06/01/14	05/24/23	885	885	885	0	0	0	0	0	0	0
Gulf Solar PPAs /1	11/17/14	11/17/40	34	34	34	34	34	34	34	34	34	34
Other Purchases Subtotal:			**1,000**	**1,000**	**1,000**	**115**	**115**	**115**	**115**	**115**	**115**	**115**

Total "Non-QF" Purchases =	**1,000**	**1,000**	**1,000**	**115**	**115**	**115**	**115**	**115**	**115**	**115**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Summer Firm Capacity Purchases Total MW:	**1,000**	**1,000**	**1,000**	**115**	**115**	**115**	**115**	**115**	**115**	**115**

1/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermitent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

Table I.B.3.3: Gulf Power Firm Purchased Power Winter MW

Summary of Gulf Power Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
None	-	-	-	-	-	-	-	-	-	-	-	-
QF Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
None	-	-	-	-	-	-	-	-	-	-	-	-
Utility Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MSCG - Kingfisher I	01/01/17	12/31/35	71	71	71	71	71	71	71	71	71	71
MSCG - Kingfisher II	01/01/17	12/31/35	38	38	38	38	38	38	38	38	38	38
SENA - (Shell)	06/01/14	05/24/23	885	885	885	0	0	0	0	0	0	0
Gulf Solar PPAs /1	11/17/14	11/17/40	0	0	0	0	0	0	0	0	0	0
Other Purchases Subtotal:			**994**	**994**	**994**	**109**	**109**	**109**	**109**	**109**	**109**	**109**
Total "Non-QF" Purchases =			**994**	**994**	**994**	**109**	**109**	**109**	**109**	**109**	**109**	**109**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Winter Firm Capacity Purchases Total MW:	**994**	**994**	**994**	**109**	**109**	**109**	**109**	**109**	**109**	**109**

1/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermitent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a zero value at the system Winter peak hour.

I.B.4 Gulf - Demand Side Management (DSM)

Gulf has continually explored and implemented cost-effective DSM programs since 1981. These programs include a number of innovative conservation/energy efficiency initiatives. Importantly, Gulf's DSM efforts through 2019 have resulted in a cumulative Summer peak reduction of more than 500 MW at the generator and an estimated cumulative energy savings of approximately 1,079 Gigawatt-Hour (GWh) at the generator. After accounting for Gulf's current 16.25% total reserve margin requirements, Gulf's highly effective DSM efforts through 2019 have eliminated the need to construct the equivalent of approximately six (6) new 100 MW generating units. Also, it is important to note that Gulf has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In 2019, the Florida Public Service Commission (FPSC) set DSM Goals for the years 2020 through 2024 for Gulf and the other Florida utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). These Goals are identical to the Goals set by the FPSC in 2014 for the years 2020 through 2024. In February 2020, Gulf filed for FPSC approval its DSM Plan with which it intends to meet the DSM Goals. In this Site Plan, Gulf assumes that the annual reduction values for Summer MW, Winter MW, and energy (MWh) set forth in the DSM Goals order (Order No. PSC-2019-0509-FOF-EG) will be met as shown in various schedules presented in this Site Plan. For the years 2025 through 2029, for which the FPSC did not establish Goals, it is assumed that DSM will be implemented to achieve the Goals Gulf proposed in its 2019 DSM Goals filing because this level of annual DSM was projected to be cost-effective.

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Gulf Power Company
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Schedule 1

Gulf Power Existing Generating Facilities
As of December 31, 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.		Actual/			
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Crist		Escambia County											
		25/1N/30W									1,135,250	924	924
	4		FS	C	NG	WA	PL	1	Jul-59	4th Q 2024	93,750	75	75
	5		FS	C	NG	WA	PL	1	Jun-61	4th Q 2026	93,750	75	75
	6		FS	C	NG	WA	PL	1	May-70	Unknown	369,750	299	299
	7		FS	C	NG	WA	PL	--	Aug-73	Unknown	578,000	475	475
Daniel (1)		Jackson County, MS											
		42/5S/6W									548,250	502	502
	1		FS	C	--	RR	--	--	Sep-77	1st Q 2024	274,125	251	251
	2		FS	C	--	RR	--	--	Jun-81	1st Q 2024	274,125	251	251
Lansing Smith		Bay County											
		36/2S/15W									697,950	686	692
	3		CC	NG	--	PL	--	--	Apr-02	Unknown	656,100	646	660
	A		CT	LO	--	TK	--	--	May-71	4th Q 2027	41,850	40	32
Pea Ridge		Santa Rosa County											
		15/1N/29W									14,250	15	12
	1		CT	NG	--	PL	--	--	May-98	2nd Q 2025	4,750	5	4
	2		CT	NG	--	PL	--	--	May-98	2nd Q 2025	4,750	5	4
	3		CT	NG	--	PL	--	--	May-98	2nd Q 2025	4,750	5	4
Perdido LFG		Escambia County											
											3,200	3	3
	1		IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,600	1.5	1.5
	2		IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,600	1.5	1.5
Scherer (1)		Monroe County, GA											
											222,750	215	215
	3		FS	C	--	RR	--	--	Jan-87	Unknown	222,750	215	215
										Total System Generating Capacity as of December 31, 2019 6/ =		**2,345**	**2,348**
										System Firm Generating Capacity as of December 31, 2019 7/ =		**2,345**	**2,348**

1/ Unit capabilities shown represent Gulf's portion of Daniel units 1 & 2 (50%) and Scherer Unit 3 (25%).

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II.A. Overview of the Load Forecasting Process

On January 1, 2019, Gulf Power became a subsidiary of NextEra Energy, the parent company of FPL. The load forecasting teams from FPL and Gulf were consolidated into one load forecasting team, which developed the forecasts of customers, sales, net energy for load (NEL), and peak demands presented in this Site Plan. Modifications were made to the standalone methodologies that were formerly applied to FPL and/or Gulf. The result is that consistent forecasting methodologies are now being applied to both the FPL and Gulf areas. These modifications are detailed later in this chapter. However, at the time this 2020 Site Plan is filed, the forecasting methodologies used to provide the load forecast information presented in this document are evolving as work to integrate the two companies is ongoing. The load forecasting team will evaluate and implement appropriate enhancements to the forecasting methodologies for upcoming forecasts.

As previously discussed, FPL and Gulf plan to integrate the two systems into a single electric system, effective 1/1/2022. In this document, the load forecasts for FPL and Gulf will be presented separately for the years 2020 and 2021. For 2022 through 2029, the load forecast for the single integrated utility will be presented. That electrically integrated system will be referred to in this document as FPL. This forecast will reflect the growth of the new integrated system, including reduced peak demand from load diversity.

FPL and Gulf typically develop long-term forecasts of customers, energy sales, and peak loads on an annual basis for each of their systems. This was done again in order to develop load forecasts for the single integrated system. Gulf's new long-term forecasts were developed in the 3rd Quarter of 2019 and FPL's new long-term forecasts were developed in the 4th Quarter of 2019[7]. The forecasts for FPL and Gulf then were combined to arrive at the forecasts for the single integrated system for the years 2022 and beyond. These new load forecasts are utilized throughout this 2020 Site Plan and are key inputs to the models used to develop the integrated resource plan presented in this document.

The following pages describe how the forecasts of customers, energy sales, and peak loads were developed first separately for FPL and Gulf, and then combined into a single set of forecasts for the integrated system. Consistent with past forecasts, the drivers for both the FPL

[7] At the time the forecasts presented in this TYSP were developed, Gulf was obligated as member of the Southern Company pool to provide updated NEL and peak demand forecasts to Southern Company Services for their planning process. The difference in the timing of the planning processes resulted in Gulf's forecast being completed prior to FPL's forecast.

and Gulf forecasts include population and household growth, economic conditions, electricity prices, weather, and energy-efficiency codes and standards. Additionally, these forecasts are 50% probability (P50) forecasts. This means there is a 50% probability that actual load will be on either side of forecasted load.

The projections for population growth, household growth, and other economic variables are obtained from IHS Markit, a leading economic forecasting firm. Using statistical models, these inputs are quantified in terms of their impact on the future demand for electricity.

Weather is a key factor that affects energy sales and peak demand. The weather variables for use in FPL's and Gulf's forecasting models are as follows:

1. The residential and commercial energy models incorporate heating degree hours and/or cooling degree hours. The threshold temperatures differ based on how each customer group responds to temperatures.
2. The Summer peak demand models incorporate maximum temperatures on the peak Summer day while the Winter peak demand models incorporate minimum temperatures on the peak Winter day. Additional details are provided later in this chapter.

FPL's weather variables are based on a composite hourly temperature using temperatures from weather stations across FPL's service area: Miami, Ft. Myers, Daytona Beach, and West Palm Beach. The temperatures for each weather station are weighted based on the energy sales associated with that region. The resulting composite temperatures are then used to derive FPL's cooling degree hours and heating degree hours used in the energy models and the peak day temperatures used in the Summer and Winter peak demand models.

Gulf's weather variables are based on the hourly temperatures from the Pensacola weather station. The Pensacola hourly temperatures are then used to derive Gulf's cooling degree hours and heating degree hours used in the energy models and the peak day temperatures used in the Summer and Winter peak demand models. The eight counties in Gulf's service area typically experience similar weather patterns and previous experience has shown that the use of multiple weather stations does not result in significant differences in the reported weather. The Pensacola weather station is used due to the availability of consistent historical data.

II.B. Customer Forecasts

FPL's customer forecasts are developed by class as the factors driving customer growth vary by class. Residential customer growth is driven by population, commercial customer growth is driven by employment and recent trends, and industrial customer growth is driven by housing starts and recent trends. Projections of population, employment, and housing starts are from IHS Markit. Total customer growth is projected to grow at an average annual rate of 1.0% during the years 2020 and 2021. The primary driver of customer growth is population.

Gulf's customer forecasts are also developed by class. Residential customer growth for 2020 and 2021 are based on projections prepared by Gulf's field marketing managers and growth for years 2022 and beyond are based on household growth projection from IHS Markit. Commercial customer growth for 2020 is based on projections prepared by Gulf's field marketing manager and commercial customer growth for years 2021 and beyond is based on residential customer growth. Industrial customer growth is driven by recent trends. Total customer growth is projected to grow at an average annual rate of 1.63% during the years 2020 and 2021. The primary driver of customer growth is population growth.

The customer forecasts for the integrated system for 2022-on is the sum of the class-level customer forecasts for FPL and Gulf, which represent 91.5% and 8.5% of the combined 2022 customers, respectively. Total customer growth is projected to grow at an average annual rate of 0.9% during the forecast period. The primary driver of customer growth is projected increase in population.

II.C. Energy Sales Forecasts

Energy sales forecasts for both FPL and Gulf were developed for the major revenue classes, wholesale energy sales, and losses. Energy adjustments, such as electric vehicles and private solar, were calculated and applied to the class-level energy sales forecasts. These forecasts were then aggregated up to arrive at the NEL forecast for each company (a bottom-up approach). Econometric models were developed using the statistical software package MetrixND.

The FPL energy sales forecast presented in this TYSP for the years 2020 and 2021 was developed using a bottom-up approach whereas prior FPL forecasts were developed using a top-down approach in which the forecast began with the NEL forecast and class-level forecasts were then adjusted to match the NEL forecast. FPL's adoption of the same bottom-up approach that has been used by Gulf has several potential benefits. This approach ensures a consistent energy sales forecasting methodology is being used for both utility systems. In addition, the bottom-up approach has the potential for enhancing both the ability to perform forecast variance analyses as actual load data becomes available and for enhancing the ability to capture different growth rates between revenue classes.

1. **Residential Sales**

FPL's residential energy sales forecast was developed using an econometric model. Residential energy sales, expressed as monthly use per customer by billing day, are a function of cooling degree hours, heating degree hours, real per capita income, the four month moving average of real electricity price increases over time, energy savings from changes to energy efficiency codes and standards, monthly binary terms, and an autoregressive term. The forecasted energy use per customer per billing day was then multiplied by the projected number of residential customers and projected billing days by month to arrive at the residential billed energy sales. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecast.

Gulf's residential energy sales forecast was also developed using an econometric model. Monthly use per customer per billing day was estimated based on historical data, normal weather, price of electricity, energy savings from changes to energy efficiency codes and standards, monthly binary terms, and an autoregressive term. The model output was then multiplied by the projected number of residential customers and projected billing days by month to expand to the total residential class.

The methodology described above for Gulf was used for the entire forecast horizon whereas prior forecasts applied this methodology only for the short-term. Growth rates from the LoadMAP-R electric utility end-use model were then used to extend the short-term residential sales forecast into the long-term forecast horizon. Gulf's adoption of the long-term model results for the entire forecast horizon ensures both FPL and Gulf are employing enhanced energy sales forecasting methodologies.

Both FPL's and Gulf's residential energy sales forecasts were adjusted to reflect the anticipated impact of continued adoption of electric vehicles. FPL's residential energy sales forecast was also adjusted to reflect the impact of private solar.

The residential energy sales forecast for the integrated system for the year 2022-on is the sum of the residential sales forecasts for FPL and Gulf, which represent, respectively, 91.5% and 8.5% of the combined 2022 residential sales. Residential energy sales are projected to grow at an average annual rate of 0.9% during the forecast period.

2. **Commercial Sales**

Econometric models were also used to develop a commercial sales forecast for FPL. The commercial class is forecast using one model for lighting accounts and three separate models based on customer size: small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demand of 500 kW or higher). Except for the commercial lighting accounts model, the commercial sales models utilize the following variables: cooling degree hours, employment, and the four month moving average of real electricity price increases. Monthly binary terms were utilized in the large and medium models; and an autoregressive term was utilized in the medium and small models. The model outputs were then multiplied by the projected number of commercial customers associated with each respective model and the projected billing days by month to arrive at the billed energy sales. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecast. The commercial lighting accounts model is based on historical sale trends and input from FPL's lighting group regarding the impact of LEDs. These forecasts are then added together to arrive at the total commercial sales forecast.

Econometric models were also used to develop a commercial non-lighting sales forecast for Gulf. The commercial non-lighting sales is forecast using two separate models which are based on customer size: small accounts (less than 25 kW of demand) and large accounts (all other commercial rate schedules excluding lighting rates). The models utilize the following variables: cooling degree hours, heating degree hours, twelve month moving average of real electricity prices, energy savings from changes to energy efficiency codes and standards, monthly binary terms, and an autoregressive term. The model outputs were then multiplied by the projected number of commercial customers associated with each respective model and the projected billing days by month to arrive at the billed energy sales. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecast. The commercial lighting sales were developed using historical growth rates and input from Gulf's lighting team to gain insight into future trends.

The methodology described above for Gulf's forecast was used for the entire forecast horizon while prior forecasts employed this methodology only for the short-term forecast. Growth rates from the LoadMAP-C electric utility end-use model are then used to extend the short-term commercial sales forecast into the long-term forecast horizon. Gulf's adoption of the long-term results for the entire forecast horizon ensures both FPL and Gulf are employing enhanced energy sales forecasting methodologies.

FPL's commercial energy sales forecast was adjusted to reflect the impact of private solar and the incremental load projected to be added for the forecast period from FPL's economic development riders.

The commercial energy sales forecast for the integrated system for the years 2022-on is the sum of the commercial sales forecasts for FPL and Gulf, which represent, respectively, 93.0% and 7.0% of the combined 2022 commercial sales. Commercial energy sales are projected to grow at an average annual rate of 0.4% during the forecast period.

3. Industrial Sales

Forecasts developed for FPL's industrial class sales consists of one model for lighting accounts and three separate models based on customer size: small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demands of 500 kW or higher). The small industrial sales model utilizes cooling degree hours, an autoregressive term, and a lagged variable. The medium, large, and lighting accounts forecasts utilize exponential smoothing models. The small, medium, large, and lighting accounts forecasts were then added together to arrive at the total industrial sales forecast.

Forecasts for Gulf's industrial class sales used a combination of surveys of major industrial customers and historical average use per customer. Gulf's largest industrial customers were interviewed by Gulf's industrial account representatives to identify expected future load changes. The forecast of sales to the remaining smaller industrial customers was developed by rate code using historical average use per customer, which was multiplied by the projected number of customers to arrive at energy sales. The forecasts for the largest industrial customers and the remaining smaller industrial customers were added together to arrive at the total industrial sales forecast.

FPL's Industrial energy sales were adjusted for forecasted Commercial/Industrial Service Rider (CISR) sales for new or retained customer loads of 2 MW or greater and meet the criteria outlined in FPL's Rate Schedule: CISR-1.

The industrial energy sales forecast for the integrated system for the years 2022-on is the sum of the industrial sales forecasts for FPL and Gulf, which represent, respectively, 65.9% and 34.1% of the combined 2022 industrial sales. Industrial energy sales are projected to remain mostly flat during the forecast period, only growing at an average annual rate of 0.2%.

4. Railroad and Railways Sales and Street and Highway Sales

FPL's Railroad and Railway class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

FPL develops the forecast for Street and Highway sales by first developing a trended use-per-customer value, then multiplying this value by the number of forecasted customers.

Gulf's street and highway class consists of outdoor lighting accounts for governmental entities and municipal services benefit units (MSBU). An MSBU is a non-ad valorem assessment district established for funding improvements, such as street lighting, in a specific geographic area. The projections for street and highway sales are based on historical growth rates and inputs from Gulf's lighting team to gain insight into future trends.

5. Other Public Authority Sales

This class is applicable only to FPL and consists of a sports field rate schedule (which is closed to new customers) and one government account. The forecast for this class is based on its historical usage characteristics.

6. Total Sales to Ultimate Customer

The sales forecasts by revenue class for FPL and Gulf are each summed to produce their respective total sales forecasts.

7. Sales for Resale

Sales for resale (wholesale) customers are comprised of sales to municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity. Instead, they resell this electricity to their own customers.

The load forecast for FPL includes wholesale loads served under full and partial-requirements contracts that provide other utilities all, or a portion of, their load requirements at a level of service equivalent to FPL's own native load customers. There are currently nine customers in this class: Florida Keys Electric Cooperative, Lee County Electric Cooperative, New Smyrna Beach, Wauchula, Homestead, Quincy, Moore Haven, Florida Public Utilities Company, and Seminole Electric Cooperative.[8]

[8] FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time this Site Plan was being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

The load forecast for Gulf also includes a full-requirements wholesale contract that provide another utility all of their load requirement at a level of service equivalent to Gulf's own native load customers. There is currently one customer in this class: Florida Public Utilities Company.

Since May 2011, FPL has provided service to the Florida Keys Electric Cooperative under a long-term, full-requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

FPL sales to Lee County began in 2010. Lee County has a contract with FPL for the full-requirements of their load that is projected to continue through 2033, with an option to extend the contract through 2053. Forecasted NEL for Lee County is based on customer-supplied information and historical usage trends.

FPL sales to New Smyrna Beach began in February 2014. The contract is projected to continue through December 2021. Under a second contract, additional sales to New Smyrna Beach began in July 2017 and are also projected to continue through December 2021. Under a third contract, sales to New Smyrna again increased beginning in January 2019 and these are also projected to continue through December 2021

FPL's sales to Wauchula began in October 2011. The contract is projected to continue through December 2023.

FPL sales to Homestead began in August 2015. The contract is projected to continue through December 2026. Under a separate contract, additional sales to Homestead began in January 2020 and are also projected to continue through December 2026.

FPL sales to Quincy began in January 2016. The contract is projected to continue through December 2023.

FPL sales to Moore Haven began in July 2016. The contract is projected to continue through December 2025.

FPL sales to Florida Public Utilities Company began in January 2018. The contract is projected to continue through December 2026.

FPL sales to Seminole Electric Cooperative are based on delivery of 200 MW that began in June 2014 and is projected to continue through May 2021.

Gulf Power sales to Florida Public Utilities Company is projected to continue through December 2026.

II.D. Net Energy for Load (NEL)

The NEL forecast for both FPL and Gulf are the sums of the retail energy, wholesale energy, and losses. Through the use of the energy efficiency variable, the retail energy sales forecast includes the impacts from major energy efficiency codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent bulbs (CFLs) and LEDs. The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and, from that year, their cumulative impact on NEL for the integrated system is projected to be a reduction of 6,028 GWh by 2029. This represents an approximately 4.2% reduction in what the forecasted NEL for 2029 would have been absent these codes and standards. From the end of 2019, the incremental reduction through 2029 is expected to be 2,482 GWh. The estimated impacts from codes and standards are based on the energy efficiency variables in the respective energy models. Previously, FPL's NEL forecast was based on a top-down approach using a single model for NEL which included an energy efficiency variable. The result of this approach assigned energy efficiency savings to all FPL customer classes.

FPL's current NEL forecast, however, is based on a bottoms-up approach using separate models for each class. The result of this approach found that the energy efficiency variables were not statistically significant[9] for the commercial customer model, and as such, the impact associated with energy efficiency on FPL's commercial sales cannot be quantified separately using the current models. While this energy efficiency impact cannot be separately quantified using the current models, this should not be interpreted as though energy efficiency is not impacting commercial customers nor that the NEL forecast is not accounting for this impact. What it means is that this impact for the commercial class is being captured in another variable within the model. However, as a result, it appears that there is a decline in the explicitly quantified energy efficiency impact on total NEL through 2029 compared to the results presented in the 2019 Site Plan. As previously mentioned, FPL routinely evaluates its

[9] The efficiency variable was highly correlated with the price term, and the resulting multicollinearity issue resulted in the variable exhibiting a high p-value. Variables with a high p-value are not statistically significant to the model.

methodologies and models for potential refinements and one area for possible refinement is in regard to separately quantifying the impact of energy efficiency codes and standards for commercial class customers.

FPL makes an adjustment for the impact of incremental private solar projected to be added during the forecast period. The impact of private solar on the NEL forecast for the integrated system is projected to be a reduction of approximately 1,311 GWh by 2029. FPL and Gulf also adjust for the additional load projected to be added due to the incremental adoption of new plug-in electric vehicles. This results in an increase on the integrated system of approximately 1,686 GWh by 2029. The forecast is also adjusted for the incremental load projected to be added to FPL's system from FPL's economic development riders forecast. This incremental load is projected to be approximately 252 GWh by 2029.

II.E. System Peak Forecasts

The rate of absolute growth in peak load for both FPL and Gulf has been a function of the size of the customer base, weather, projected economic conditions, and energy-efficiency codes and standards. The peak forecast models capture these behavioral relationships. In addition, the peak forecast for FPL also reflects changes in load expected from private solar, the expected number of plug-in electric vehicles, FPL's economic development riders, and wholesale requirements contracts. With respect to the peak forecast for Gulf, the projected impacts of private solar and electric vehicles are believed to be relatively small. However, the ability to better incorporate projected impacts of private solar and EVs in Gulf's area is another aspect of the current forecasting methodologies for which the load forecasting team will evaluate for additional refinements in upcoming forecasts.

The monthly peak load for the integrated system from 2022-on is the highest hourly demand from the forecasted system hourly load forecast, which was developed by summing the forecasted system hourly loads for FPL and Gulf. The integrated system peak load forecast reflects the growth in peak load for FPL and Gulf along with the peak demand savings associated with load diversity.

As separate systems, FPL and Gulf peak at different hours and this difference is due to load diversity. The load diversity is primarily due to their respective loads being located in different time zones and the benefit of load diversity is that the combined system peak demand is lower than the sum of the standalone FPL and Gulf peaks demands. By 2029, the load diversity results in a projected reduction to the integrated system peaks of 103 MW in the Summer and 190 MW in the Winter. This represents savings for customers.

The savings from energy-efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of CFLs and LEDs. The impact from these energy-efficiency standards began in 2005, and their cumulative reduction, from that year, on the integrated Summer peak is projected to reach approximately 5,732 MW by 2029. This reduction includes engineering estimates and any resulting behavioral changes.

The cumulative 2029 impact from these energy-efficiency codes and standards is projected to effectively reduce the integrated system's Summer peak for that year by approximately 19%. From the end of 2019, the projected incremental impact on the Summer peak from these energy-efficiency codes and standards is a reduction of approximately 1,848 MW through 2029.

The peak forecast for FPL was also adjusted for the additional load estimated from private solar, plug-in electric vehicles, and FPL's economic development riders. The impact from plug-in electric vehicles is projected to be an increase on the integrated system of approximately 582 MW in the Summer and 291 MW in the Winter by the end of 2029. The impact on the integrated system from FPL's economic development riders is projected to be an increase of approximately 29 MW in the Summer peak and 61 MW in the Winter peak. The incremental impact of private solar on the integrated system is an expected decrease of approximately 327 MW in the Summer and a negligible reduction in the Winter by the end of 2029.

The forecasting methodology for Summer, Winter, and monthly system peaks is discussed below.

The forecasted values for FPL's and Gulf's Summer and Winter peak loads for the years 2020 through 2021 are presented separately at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2. For the years 2022 through 2029, only forecasted values for the integrated system are presented on these schedules.

1. System Summer Peak

The Summer peak forecast for FPL is developed using an econometric model based on the Summer peak contribution per customer. The variables included in the model are Florida real per capita income, cooling degree hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency codes and standards, binary variables years 2005 and 2019, and autoregressive terms. The model output is multiplied by the total number of customers to arrive at the projected Summer peak demand. This product is then adjusted to account for the expected changes in loads resulting from private solar, plug-in electric vehicles, FPL's economic development riders, and wholesale requirements contracts to derive FPL's system Summer peak.

The Summer peak forecast for Gulf is developed using an econometric model based on the Summer peak contribution per customer. The variables included in the model are the maximum temperature on the day of the peak, a variable for energy efficiency codes and standards, employment-weighted real per capita income, and an autoregressive term. The model output is multiplied by the total number of customers to arrive at the projected Summer peak demand.

Summer peak forecasts presented in Gulf's prior Site Plans were developed using the Peak Demand Model (PDM) which spread the energy projections using historical load shapes to develop forecasted hourly load shapes and the monthly forecast peak demand was the single highest hour in each month. Adoption of the econometric modeling approach for Summer peak forecast ensures FPL and Gulf are employing enhanced peak demand forecasting methodologies.

The Summer peak demand forecast for the integrated system for 2022-on is the highest hourly demand during the Summer months from the integrated system hourly forecast, which was developed by summing the forecasted system hourly loads for FPL and Gulf. This approach ensures the Summer peak demand forecast for the integrated system reflects the growth in Summer peak load for FPL and Gulf along with the Summer peak demand savings associated with load diversity. The Summer peak demand for the integrated system is projected to occur in August.

2. System Winter Peak

The Winter peak forecast for FPL is developed using an econometric model based on the Winter peak contribution per customer. The variables included in the model are employment-weighted real per capita income, the minimum temperature on the peak day, a weather-related variable capturing cold buildup, a binary variable for year 2008, and a trend variable. The model output is multiplied by the total number of customers to arrive at the projected Winter peak demand. The projection is then adjusted for the expected changes in loads resulting from private solar, plug-in electric vehicles, FPL's economic development riders, and wholesale requirement contracts.

The Winter peak forecast for Gulf was developed using an econometric model based on the Winter peak contribution per customer. The variables included in the model are the minimum temperature on the peak day, a variable for energy efficiency codes and standards, and autoregressive terms. The model output is then multiplied by the total number of customers to arrive at the projected Winter peak demand.

The Winter peak forecasts presented in prior Gulf Site Plans were developed using the PDM model. Adoption of the econometric modeling approach for Winter peak forecast ensures FPL and Gulf are employing enhanced peak demand forecasting methodologies.

The Winter peak demand forecast for the integrated system is the highest hourly demand during the Winter months from the integrated system hourly forecast. This approach ensures the integrated Winter peak demand forecast reflects the growth in the Winter peak load for FPL and Gulf along with the Winter peak demand savings associated with load diversity. The Winter peak demand for the integrated system is projected to occur in January.

3. Monthly Peak Forecasts

The forecasting process for FPL's monthly peaks begins with two assumptions. First, the forecasted annual Summer peak is assumed to occur in the month of August, which historically has accounted for more annual Summer peaks than any other month. Second, the forecasted annual Winter peak is assumed to occur in the month of January, which historically has accounted for more annual Winter peaks than any other month. Then the remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual Summer peak.

The forecasting process for Gulf's monthly peaks begins with two assumptions. First, the forecasted annual Summer peak is assumed to occur in the month of July, which historically has accounted for more annual Summer peaks than any other month. Second, the forecasted annual Winter peak is assumed to occur in the month of January, which historically has accounted for more annual Winter peaks than any other month. Then the remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual Summer peak.

Monthly peak forecasts presented in prior Gulf Site Plans were developed using the PDM model. Gulf's adoption of FPL's monthly peak demand forecast process ensures FPL and Gulf are employing enhanced monthly peak demand forecasting methodologies.

The monthly peak demand forecast for the integrated system for 2022-on is the highest hourly demand by month from the integrated system hourly forecast. This approach ensures the integrated monthly peak demand forecast reflects the growth in monthly peaks for FPL and Gulf along with the monthly peak demand savings associated with load diversity.

II.F. Hourly Load Forecast

Forecasted values for system hourly load on the FPL system for the period 2020 through 2029 were developed using a system load forecasting program named MetrixLT. This model uses years of historical FPL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of FPL's monthly peaks and energy.

Forecasted values for system hourly load on the Gulf system for the period 2020 to 2029 were also developed using MetrixLT, which uses historical Gulf hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of Gulf's monthly peaks and energies.

The forecasted values for system hourly load on the integrated system for 2022-on were the summation of the FPL and Gulf hourly load for the period. The Gulf system hourly load was adjusted from Central to Eastern time zone to be consistent with FPL's system hourly load.

II.G. Uncertainty

Uncertainty is inherent in the load forecasting process. This uncertainty can result from a number of factors, including unexpected changes in consumer behavior, structural shifts in the economy, and fluctuating weather conditions. Large weather fluctuations, in particular, can result in significant deviations between actual and forecasted peak demands. The load forecast is based on average expected or normal weather conditions. An extreme 90% probability (P90) cold weather event can add an additional 3,000 MW or more to the Winter peak, and an extreme P90 hot weather event can add an additional 750 MW to the Summer peak.

In order to address uncertainty in the forecast of aggregate peak demand and NEL, the assumptions underlying the forecasts are first evaluated. Then a series of steps are taken to evaluate the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. Additional factors that may affect the input variables are reviewed as needed.

Uncertainty is also addressed in the modeling process. Econometric models generally are used to forecast peak demands and energies. During the modeling process, relevant statistics such as (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are thoroughly understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as they become available. An ongoing process of variance analyses is performed. To the extent the variance analyses identify large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered. Finally, the forecasting group regularly engages with forecasting professionals from other electric utilities to share best practices and changes to existing processes may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to the overall resource planning and operational planning work. With respect to resource planning work, the utilization of a 20% total reserve margin (TRM) criterion, a Loss-of-Load-Probability (LOLP) criterion of 0.1, and a 10% generation-only reserve margin (GRM) criterion are designed to maintain reliable electric service for customers in light of forecasting and other uncertainties. In addition, banded forecasts of the projected Summer peak and NEL may be produced based on an analyses of past forecasting variances. A banded forecast for the projected Summer and Winter peak days may also be developed based on historical weather variations. These bands are then used to develop similar bands for the monthly peaks. A P80 monthly peak forecast is typically provided to FPL’s System Operations group for operational planning purposes.

II.H. DSM

FPL and Gulf assume that the effects of its DSM energy-efficiency programs through August 2019 are embedded in the actual usage data for forecasting purposes. In addition, the utilities account for the following projected DSM MW and MWh impacts as “line item reductions” to the forecasts as part of the IRP process: 1) the impacts of incremental energy efficiency that the utilities have implemented in the September 2019 through December 2019 time period (*i.e.*, after the 2019 Summer peak has occurred), 2) projected impacts from incremental energy efficiency that FPL plans to implement in 2020 through 2024 in response to the DSM Goals that were set for each utility by the FPSC in the 4th Quarter of 2019 for the 2020 – 2024 time period, 3) the inclusion of additional currently projected cost-effective DSM for the years 2025 through 2029, and 4) the cumulative and projected incremental impacts of FPL’s load management programs through 2029. After making these adjustments to the load forecasted load values, the resulting "firm" load forecast as shown in Chapter III in Schedules 7.1 and 7.2., is then used in the IRP work.

Schedule 2.1: FPL
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2010	8,851,966	2.21	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,979,403	2.23	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	9,096,135	2.24	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,219,688	2.25	53,930	4,097,172	13,163	45,341	516,500	87,786
2014	9,357,139	2.24	55,202	4,169,028	13,241	45,684	525,591	86,919
2015	9,517,833	2.25	58,846	4,227,425	13,920	47,369	532,731	88,916
2016	9,687,433	2.26	58,687	4,284,159	13,699	47,355	540,356	87,637
2017	9,824,821	2.26	58,188	4,338,224	13,413	47,151	547,908	86,056
2018	10,004,467	2.28	59,096	4,391,832	13,456	47,394	553,562	85,616
2019	10,119,121	2.26	60,325	4,479,356	13,467	48,078	565,622	85,000

Historical Values (2010 - 2019):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1: Gulf
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2010	873,320	2.32	5,651	375,847	15,036	3,997	53,349	74,912
2011	882,950	2.33	5,305	378,157	14,028	3,911	53,409	73,235
2012	898,710	2.37	5,054	379,897	13,303	3,859	53,706	71,846
2013	911,720	2.38	5,089	382,599	13,301	3,810	54,261	70,215
2014	923,520	2.39	5,362	386,765	13,865	3,838	54,749	70,104
2015	936,420	2.39	5,365	391,465	13,705	3,898	55,234	70,566
2016	949,240	2.39	5,358	396,408	13,515	3,869	55,876	69,236
2017	962,790	2.40	5,229	401,793	13,015	3,814	56,428	67,583
2018	977,810	2.40	5,519	406,949	13,563	3,829	56,892	67,298
2019	990,370	2.43	5,520	407,436	13,548	3,775	56,590	66,710

Historical Values (2010 - 2019):

Col. (2) includes the Pensacola, Crestview, and Panama City MSAs, which are generally representative of the area served by Gulf.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
				FPL				
2020	10,227,063	2.26	59,382	4,527,529	13,116	48,037	572,459	83,914
2021	10,335,192	2.26	59,814	4,568,149	13,094	48,469	579,245	83,677
				Gulf				
2020	1,000,760	2.42	5,405	414,018	13,029	3,646	57,318	63,564
2021	1,010,360	2.40	5,433	421,341	12,852	3,629	57,932	62,563
				Integrated FPL and Gulf				
2022	11,465,461	2.28	65,314	5,036,516	12,963	52,262	644,416	81,100
2023	11,586,120	2.28	65,784	5,084,160	12,932	52,440	650,778	80,581
2024	11,708,833	2.28	66,480	5,129,346	12,952	52,735	656,117	80,374
2025	11,832,535	2.29	66,969	5,173,248	12,937	52,937	660,837	80,107
2026	11,956,071	2.29	67,586	5,217,662	12,945	53,177	665,392	79,918
2027	12,080,045	2.30	68,285	5,261,200	12,971	53,433	669,923	79,760
2028	12,204,016	2.30	69,176	5,303,021	13,037	53,783	674,471	79,741
2029	12,328,021	2.31	69,845	5,344,810	13,060	53,871	679,110	79,326

Projected Values (2020 - 2029):

Col. (2) represents population in the areas served by FPL and Gulf separately for 2020 and 2021, and by the single integrated system for 2022 - 2029

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2: FPL
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	& Railways GWh	Highway Lighting GWh	Public Authorities GWh	Ultimate Consumers GWh
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784
2014	2,941	10,415	282,398	91	446	24	104,389
2015	3,042	11,318	268,799	92	448	23	109,820
2016	3,059	11,770	259,853	92	447	23	109,663
2017	2,961	11,654	254,103	83	446	41	108,871
2018	3,013	11,601	259,728	80	447	23	110,053
2019	2,994	11,799	253,759	82	428	23	111,929

Historical Values (2010 - 2019):

Col. (16) represents actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2: Gulf
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	& Railways GWh	Highway Lighting GWh	Public Authorities GWh	Ultimate Consumers GWh
2010	1,686	275	6,133,961	0	26	0	11,359
2011	1,799	273	6,586,591	0	25	0	11,040
2012	1,725	267	6,453,071	0	25	0	10,663
2013	1,700	258	6,581,320	0	21	0	10,620
2014	1,849	258	7,165,343	0	25	0	11,075
2015	1,798	249	7,235,499	0	25	0	11,086
2016	1,830	247	7,402,625	0	25	0	11,082
2017	1,740	255	6,815,486	0	26	0	10,809
2018	1,757	253	6,931,497	0	28	0	11,132
2019	1,756	250	7,026,958	0	28	0	11,079

Historical Values (2010 - 2019):

Col. (16) represents actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	GWh	GWh	GWh
FPL							
2020	3,071	12,244	250,838	80	401	20	110,993
2021	3,152	12,722	247,739	80	399	20	111,934
Gulf							
2020	1,738	251	6,923,042	0	28	0	10,816
2021	1,663	251	6,624,257	0	28	0	10,752
Integrated FPL and Gulf							
2022	4,874	13,270	367,281	80	417	20	122,968
2023	4,875	13,414	363,429	80	420	20	123,619
2024	4,875	13,469	361,955	80	429	20	124,619
2025	4,876	13,559	359,611	80	450	20	125,333
2026	4,877	13,648	357,302	80	456	20	126,195
2027	4,876	13,640	357,499	80	462	20	127,156
2028	4,876	13,589	358,814	80	462	20	128,398
2029	4,876	13,570	359,309	80	462	20	129,154

Projected Values (2020 - 2029):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3: FPL
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934
2014	5,375	6,204	115,968	3,795	4,708,829
2015	6,610	6,326	122,756	3,907	4,775,382
2016	6,623	5,334	121,619	3,994	4,840,279
2017	6,406	5,468	120,745	4,100	4,901,886
2018	6,790	5,604	122,447	4,334	4,961,330
2019	7,315	5,924	125,168	4,749	5,061,525

Historical Values (2010 - 2019):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2019 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

Schedule 2.3: Gulf
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2010	409	750	12,518	559	430,030
2011	382	663	12,086	564	432,403
2012	339	597	11,598	572	434,441
2013	330	602	11,552	579	437,698
2014	332	629	12,037	598	442,370
2015	330	580	11,996	610	447,557
2016	331	618	12,030	609	453,140
2017	318	588	11,715	574	459,050
2018	302	623	12,057	589	464,682
2019	257	407	11,742	608	464,884

Historical Values (2010 - 2019):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy For Load GWh	Average No. of Other Customers	Total Average Number of Customers
			FPL		
2020	6,283	5,797	123,073	5,100	5,117,332
2021	5,788	5,412	123,134	5,458	5,165,574
			Gulf		
2020	298	601	11,715	603	472,190
2021	293	597	11,643	606	480,130
			Integrated FPL and Gulf		
2022	5,717	6,115	134,800	6,419	5,700,622
2023	5,793	6,189	135,600	6,783	5,755,134
2024	5,871	6,271	136,761	7,141	5,806,073
2025	5,948	6,260	137,540	7,499	5,855,142
2026	6,028	6,318	138,541	7,858	5,904,561
2027	5,955	6,363	139,474	8,215	5,952,978
2028	6,040	6,437	140,874	8,572	5,999,654
2029	6,125	6,472	141,751	8,931	6,046,421

Projected Values (2020 - 2029):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18).

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

Florida Power & Light Company
Gulf Power Company
Docket No. 20200000-OT
Staff's First Data Request
Request No. 1
Attachment No. 1
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Schedule 3.1: FPL
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,417	833	839	19,718
2014	22,935	1,155	21,780	0	1,010	1,494	843	866	21,082
2015	22,959	1,303	21,656	0	878	1,523	826	873	21,255
2016	23,858	1,367	22,491	0	882	1,548	836	888	22,140
2017	23,373	1,393	21,980	0	910	1,560	825	903	21,639
2018	23,217	1,338	21,879	0	866	1,571	866	916	21,485
2019	24,241	1,292	22,949	0	852	1,579	879	926	22,510

Historical Values (2010 - 2019):

Col. (2) and Col. (3) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col.(6) values for 2015-on reflect a hardware communications issue identified in 2015 that was subsequently resolved. A number of participating customers did not respond to FPL's efforts to reach them or refused access to correct the equipment problem at their home. As a result, these customers were removed from the program.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.1: Gulf
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2010	2,525	88	2,437	0	0	178	0	192	2,525
2011	2,535	89	2,446	0	0	186	0	198	2,535
2012	2,351	76	2,275	0	0	206	0	212	2,351
2013	2,362	74	2,288	0	0	229	0	220	2,362
2014	2,437	75	2,362	0	0	243	0	224	2,437
2015	2,495	78	2,417	0	0	256	0	231	2,495
2016	2,508	76	2,432	0	0	261	0	231	2,508
2017	2,434	74	2,360	0	0	266	0	232	2,434
2018	2,491	80	2,411	0	0	268	0	233	2,491
2019	2,472	75	2,397	0	0	269	0	233	2,472

Historical Values (2010 - 2019):

Col. (2) and Col. (3) are actual values for historical Summer peaks and include the effects of conservation (Col. 7 & Col. 9).

Col. (4) represents "Retail Demand" and is derived by the formula: Col. (2) - Col. (3).

Col. (10) is derived by the formula Col. (10) = Col. (2) - Col. (6) - Col. (8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
					FPL				
2020	24,624	1,540	23,084	0	856	11	907	11	22,838
2021	24,720	1,367	23,353	0	865	23	918	27	22,887
					Gulf				
2020	2,464	64	2,399	0	0	5	0	1	2,458
2021	2,496	64	2,432	0	0	12	0	2	2,481
					Integrated FPL and Gulf				
2022	27,220	1,384	25,836	0	873	55	928	47	25,317
2023	27,564	1,406	26,158	0	882	76	939	65	25,602
2024	27,953	1,399	26,554	0	894	98	949	84	25,927
2025	28,349	1,405	26,944	0	915	105	960	92	26,278
2026	28,775	1,425	27,350	0	939	105	971	92	26,668
2027	29,143	1,357	27,786	0	963	105	982	92	27,001
2028	29,592	1,376	28,216	0	987	105	993	92	27,415
2029	30,195	1,396	28,799	0	1,012	105	1,004	92	27,983

Projected Values (2020 - 2029):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent incremental and cumulative load management, and incremental conservation.
All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.2: FPL
History of Winter Peak Demand (MW)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521
2014	17,500	890	16,610	0	828	805	590	337	16,083
2015	19,718	1,329	18,389	0	822	835	551	346	18,345
2016	17,031	1,087	15,944	0	742	858	570	352	15,719
2017	17,172	1,098	16,074	0	759	861	577	364	15,836
2018	19,109	1,262	17,847	0	750	864	588	369	17,771
2019	16,795	1,432	15,363	0	706	867	613	379	15,476

Historical Values (2010 - 2019):

Col. (2) and Col. (3) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand. For year 2011, the actual winter peak occurred in December of 2010.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col.(6) values for 2015-on reflect a hardware communications issue identified in 2015 that was subsequently resolved. A number of participating customers did not respond to FPL's efforts to reach them or refused access to correct the equipment problem at their home. As a result, these customers were removed from the program.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.2: Gulf
History of Winter Peak Demand (MW)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2010	2,553	99	2,454	0	0	289	0	154	2,553
2011	2,495	89	2,406	0	0	297	0	157	2,495
2012	2,139	70	2,069	0	0	317	0	165	2,139
2013	1,766	90	1,676	0	0	341	0	169	1,766
2014	2,694	85	2,609	0	0	356	0	172	2,694
2015	2,492	74	2,418	0	0	369	0	176	2,492
2016	2,043	80	1,963	0	0	374	0	176	2,043
2017	2,211	89	2,122	0	0	377	0	177	2,211
2018	2,809	70	2,739	0	0	379	0	178	2,809
2019	2,066	66	2,000	0	0	381	0	178	2,066

Historical Values (2010 - 2019):

Col. (2) and Col. (3) are actual values for historical Winter peaks and include the effects of conservation (Col. 7 & Col. 9).

Col. (4) represents "Retail Demand" and is derived by the formula: Col. (2) - Col. (3).

Col. (10) is derived by the formula Col. (10) = Col. (2) - Col. (6) - Col. (8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
					FPL				
2020	19,959	1,230	18,729	0	712	3	634	10	18,599
2021	20,250	1,248	19,002	0	721	5	640	20	18,863
					Gulf				
2020	2,256	69	2,187	0	0	0	0	0	2,256
2021	2,293	68	2,225	0	0	4	0	1	2,287
					Integrated FPL and Gulf				
2022	22,369	1,068	21,301	0	733	16	647	33	20,939
2023	22,617	1,108	21,509	0	746	24	653	46	21,149
2024	22,861	1,139	21,722	0	758	32	659	58	21,353
2025	23,103	1,140	21,963	0	778	40	666	70	21,548
2026	23,388	1,172	22,216	0	804	40	671	70	21,803
2027	23,608	1,118	22,490	0	829	40	676	70	21,992
2028	23,941	1,155	22,786	0	855	40	681	70	22,294
2029	24,293	1,181	23,112	0	880	40	686	70	22,616

Projected Values (2020 - 2029):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent incremental and cumulative load management, and incremental conservation.
All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.3: FPL
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Actual Total Retail Sales (GWh)	(9) Load Factor(%)
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	53.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%
2014	121,621	3,125	2,529	115,968	5,375	6,204	104,389	57.7%
2015	128,555	3,232	2,568	122,756	6,610	6,326	109,820	61.0%
2016	127,481	3,254	2,608	121,619	6,623	5,334	109,663	58.0%
2017	126,680	3,278	2,655	120,747	6,406	5,470	108,871	59.0%
2018	128,465	3,300	2,718	122,447	6,790	5,604	110,053	60.2%
2019	131,241	3,322	2,751	125,168	7,315	5,924	111,929	58.9%

Historical Values (2010 - 2019):

Col. (2) represents derived NEL not including conservation using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5)

Col. (3) & Col. (4) are annual (12-month) DSM values and represent total GWh reductions experienced each year.

Col. (8) is the Total Retail Sales calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and the greater of Col. (2) from Schedules 3.1 and 3.2 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 3.3: Gulf
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Retail Energy Sales (GWh)	(9) Load Factor(%)
2010	13,256	388	350	12,518	409	750	11,359	56.0%
2011	12,864	417	361	12,086	382	663	11,040	54.4%
2012	12,453	482	374	11,598	339	597	10,663	56.2%
2013	12,502	551	399	11,552	330	602	10,620	55.8%
2014	13,048	595	416	12,037	332	629	11,075	51.0%
2015	13,056	630	430	11,996	330	580	11,086	54.9%
2016	13,097	637	430	12,030	331	618	11,082	54.6%
2017	12,789	642	432	11,715	318	588	10,809	54.9%
2018	13,138	647	435	12,057	302	623	11,132	49.0%
2019	12,828	650	436	11,742	257	407	11,079	54.2%

Historical Values (2010 - 2019):

Col. (2) represents derived NEL not including conservation using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5)

Col. (3) & Col. (4) are annual (12-month) DSM values and represent total GWh reductions experienced each year.

Col. (8) is the Total Retail Sales calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and the greater of Col. (2) from Schedules 3.1 and 3.2 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Forecasted Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Net Energy For Load Adjusted for DSM GWh	Sales for Resale GWh	Utility Use & Losses GWh	Forecasted Total Billed Retail Energy Sales w/o DSM GWh	Load Factor(%)
				FPL				
2020	123,073	30	35	123,007	6,283	5,538	111,252	56.9%
2021	123,134	56	65	123,013	5,788	5,538	111,808	56.8%
				Gulf				
2020	11,715	10	3	11,702	298	601	10,816	54.1%
2021	11,643	18	5	11,620	293	597	10,752	53.2%
				Integrated FPL and Gulf				
2022	134,800	108	103	134,588	5,717	6,133	122,949	56.4%
2023	135,600	144	138	135,318	5,793	6,167	123,640	56.0%
2024	136,761	181	175	136,405	5,871	6,217	124,673	55.6%
2025	137,540	181	175	137,184	5,948	6,252	125,340	55.2%
2026	138,541	181	175	138,185	6,028	6,297	126,216	54.8%
2027	139,474	181	175	139,118	5,955	6,339	127,180	54.5%
2028	140,874	181	175	140,518	6,040	6,402	128,432	54.1%
2029	141,751	181	175	141,395	6,125	6,442	129,184	53.5%

Projected Values (2020 - 2029):

Col. (2) represents Forecasted NEL and does not include incremental conservation.

Col. (3) & Col. (4) are forecasted values representing reduction on sales from incremental conservation

Col. (5) is forecasted NEL adjusted for incremental conservation.

Col. (8) is Total Retail Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (10) from Schedule 3.1 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 4: FPL
Previous Year Actual and Two-Year Forecast of
Total Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2019 ACTUAL		2020 FORECAST		2021 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	16,795	8,672	19,959	8,890	20,250	8,861
FEB	18,660	8,353	19,005	8,311	19,233	8,124
MAR	18,963	9,159	18,900	9,155	19,127	9,254
APR	20,106	9,899	20,255	9,522	20,499	9,598
MAY	22,580	11,417	22,150	10,879	22,416	10,987
JUN	24,241	11,775	23,700	11,437	23,792	11,428
JUL	23,583	12,481	24,190	12,312	24,284	12,274
AUG	22,861	12,145	24,624	12,402	24,720	12,425
SEP	23,653	11,803	23,652	11,439	23,745	11,430
OCT	21,776	11,633	22,210	10,732	22,296	10,711
NOV	19,855	9,001	19,601	8,962	19,678	8,978
DEC	17,249	8,830	18,737	9,030	18,810	9,064
Annual Values:		**125,168**		**123,073**		**123,134**

Col. (3) annual value shown is consistent with the value shown in Col.(5) of Schedule 3.3.

Cols. (4) through (7) do not include the impacts of cumulative load management, incremental utility conservation, or incremental load management.

Schedule 4: Gulf
Previous Year Actual and Two-Year Forecast of
Total Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2019 ACTUAL		2020 FORECAST		2021 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	2,066	941	2,256	967	2,293	950
FEB	1,564	725	1,955	837	1,980	809
MAR	1,885	817	1,726	800	1,749	796
APR	1,734	808	1,733	809	1,756	801
MAY	2,260	1,087	2,137	991	2,165	986
JUN	2,444	1,210	2,359	1,146	2,389	1,146
JUL	2,426	1,291	2,464	1,254	2,496	1,254
AUG	2,374	1,187	2,411	1,240	2,442	1,239
SEP	2,472	1,163	2,265	1,078	2,294	1,076
OCT	2,284	959	1,997	909	2,023	906
NOV	1,951	730	1,710	794	1,732	792
DEC	1,862	825	1,894	889	1,919	888
Annual Values:		**11,742**		**11,715**		**11,643**

Col. (3) annual value shown is consistent with the value shown in Col.(5) of Schedule 3.3.

Cols. (4) through (7) do not include the impacts of incremental conservation.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A. FPL's Resource Planning:

FPL utilizes its well-established, integrated resource planning (IRP) process, in whole or in part as dictated by analysis needs, to determine: (i) the magnitude and timing of needed resources, and (ii) the type of resources that should be added. This section describes FPL's basic IRP process which was used during 2019 and early 2020 to develop the resource plan for FPL's and Gulf's areas that is presented in this 2020 Site Plan. It also discusses some of the key assumptions, in addition to a new load forecast discussed in the previous chapter, which were used in developing this resource plan.

Four Fundamental Steps of FPL's Resource Planning:

The four fundamental steps of FPL's resource planning process are:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of projected resource needs (*e.g.*, identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of IRP Process: Fundamental Steps

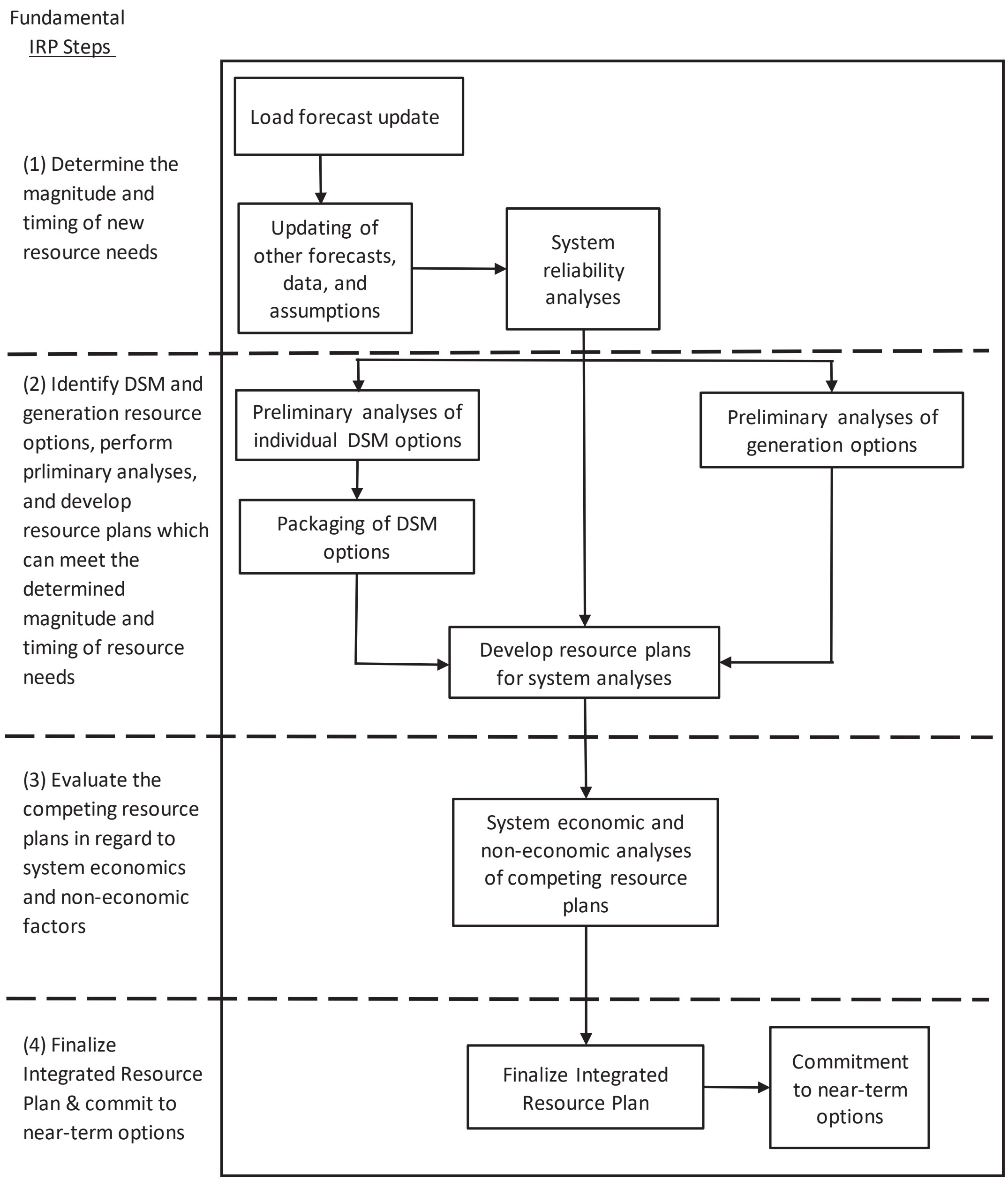

Figure III.A.1: Overview of IRP Process

Step 1: Determine the Magnitude and Timing of New Resource Needs:

The first of the four resource planning steps is essentially a determination of the amount and timing of megawatts (MW) of load reduction, new capacity additions, or a combination of both, which are needed to maintain and/or enhance system reliability. This step is often referred to as a reliability assessment for the utility system.

This analysis typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used throughout other aspects of FPL's resource planning process. Examples of this new information include but are not limited to: delivered fuel price projections, current financial and economic assumptions, current power plant capability and operating assumptions, and current demand side management (DSM) demand and energy reduction assumptions.

FPL's process also includes key sets of projections regarding three specific types of resources: (1) generating unit capacity changes, (2) firm capacity power purchase agreements (PPAs), and (3) DSM implementation.

Key Assumptions Regarding the Three Types of Resources:

The first set of assumptions, generating unit capacity changes, is based on current projections of new generating capacity additions and planned retirements of existing generating units. In this 2020 Site Plan, there are five (5) types of projected generation capacity changes through the 10-year reporting time frame of this document. These changes are listed below in general chronological order:

1) Additional Solar Energy Facilities:
   In this 2020 Site Plan, the resource plan projects the addition of approximately 8,860 MW of new solar PV generation during the 2020 through 2029 time period. Of that total addition, approximately 7,300 MW are projected to be in FPL's area and approximately 1,560 MW are projected to be in Gulf's area. These PV additions are consistent with FPL's "30-by-30" announcement in January 2019 which detailed FPL's plans to add 30 million solar PV panels cost-effectively by the year 2030. These projected solar additions for 2020 through 2029, when combined with solar additions made prior to 2020, will result in a total of approximately 10,000 MW of total installed solar by the end of 2029.

2) Additional Battery Storage:

FPL's 2019 Site Plan showed the planned addition of approximately 469 MW of battery storage in late 2021 with the majority of that storage capacity being sited in Manatee County as partial replacement for the generating capacity that will be decreased by the retirement of Manatee Units 1 & 2 (as discussed below). The current resource plan presented in this 2020 Site Plan continues to show these 469 MW of battery storage by the end of 2021. The current plan is to site 409 MW of battery storage in Manatee County and two 30 MW battery storage facilities at different sites. In addition, this resource plan projects another 700 MW of battery storage facilities by the end of 2029 with these facilities being sited in Gulf's area.

3) Retirement of Existing Generating Units:

As discussed in FPL's 2019 Site Plan, FPL plans to retire its Manatee Units 1 and 2 in late 2021. These units are older steam generating units of approximately 800 MW each that have been in operation for more than 40 years. The units are relatively inefficient units in regard to their ability to convert fuel into electricity. As a result, they are projected to no longer be cost-effective to operate for FPL's customers.

In this 2020 Site Plan, these two Manatee units are still projected to be retired in late 2021. In addition, FPL's ownership portion (approximately 630 MW) of the Scherer 4 coal-fueled unit in Georgia is planned to be retired by year-end 2021/beginning of 2022. Furthermore, Gulf's ownership portion of Daniels Units 1 & 2 is now projected to be retired by January of 2024. The Daniels units are coal-fueled units located in Mississippi Power's service territory. Gulf's ownership portion of those two units is approximately 510 MW.

4) Enhancements of Existing Generating Units:

FPL's 2019 Site Plan discussed a plan to upgrade CT components in a number of its CC units, and these upgrades are again reflected in the 2020 Site Plan. In addition, the 2020 Site Plan projects another capacity upgrade effort for existing CC units in both FPL's and Gulf's areas. These additional upgrades are projected to be completed in 2026 and to result in increased Summer capacity of approximately 600 MW, plus improved heat rates for each host CC unit. The results of all of the upgrades are included in the information presented in Schedule 8 in this chapter.

Two significant enhancements to existing generating units in the Gulf area are also included in the resource plan presented in this Site Plan. The first of those is the conversion of Crist Units 6 & 7 from coal-fueled to natural gas-fueled. This conversion effort is already underway and is scheduled to be completed in September of 2020**.** This enhancement will result in both lower cost energy generated by the units, and in significant fixed cost savings, particularly for Gulf area customers. The second enhancement is a pair of capacity upgrades of the Lansing Smith Unit 3. The installation phase of the first upgrade of this existing CC unit was completed in 2019 which will be followed by testing and tuning in the Spring of 2020. This upgrade is projected to increase the firm capacity of the unit by more than 80 MW. A second upgrade of the unit is planned for 2024 which is projected to increase unit capacity by approximately another 59 MW. Both upgrades in this second enhancement will also result in cost savings for customers through both the deferral of future capacity needs and by increased output of lower cost natural gas-fueled energy production.

5) <u>Addition of Cost-Effective Natural Gas-Fueled Generation:</u>
   In its 2019 Site Plan, FPL's resource plan projected the addition of three new CC units with one each being added in 2019, 2022, and 2026. Gulf's 2019 Site Plan projected the addition of a single new CC unit in 2024.

   The first of the FPL projected CC units in last year's Site Plan was the Okeechobee Clean Energy Center unit which became operational on FPL's system in 2019. This new CC unit supplies approximately 1,778 MW of firm capacity that can be delivered around the clock. The second of these is the Dania Beach Clean Energy Center Unit 7 that will come in-service in 2022. This unit is a key component of the modernization of FPL's existing Lauderdale power plant site. The third CC projected in FPL's 2019 Site Plan was a new CC unit being added in 2026 at a yet-to-be-determined site. Gulf's 2019 Site Plan projected a single new CC unit to be added at the Escambia site in 2024.

   The resource plan presented in this 2020 Site Plan continues to show the new Dania Beach CC unit coming in-service in 2022. However, neither the other CC unit previously projected in FPL's area for 2026, nor the Escambia CC unit in Gulf's area previously projected for 2024, remain in the current resource plan. However, four new combustion turbine (CT) units at the Crist plant site in Gulf's area are now part of the resource plan. These new CT units are being added based on system economics and for purposes of ensuring adequate fast-start operating reserves in Gulf's area.

The second set of assumptions involves other firm capacity power purchase agreements (PPAs). These assumptions are generally consistent with those presented in FPL's 2019 Site Plan and Gulf's 2019 Site Plan.

In regard to FPL's area, the most significant firm capacity PPA is with Indiantown Cogeneration LP (ICL). On January 5, 2017, with mutual consent of the parties involved and FPSC approval (in Order PSC-16-0506-FOF-EI), FPL acquired the equity interests in this coal-based PPA with ICL. This approval included both the PPA and the underlying asset (*i.e.*, the generating unit) from which FPL received firm capacity and energy. The plan is to terminate this PPA by the end of the 4th Quarter of 2020 upon retirement of the senior debt in the project. In addition, the coal-fueled generating unit upon which the PPA was based will also be retired.

In regard to Gulf's area, the most significant firm capacity PPA is the Shell PPA with which Gulf receives 885 MW of firm capacity and energy from a CC unit in Alabama. That PPA is scheduled to terminate in May of 2023. At the time this document is being prepared, Alabama Power is seeking approval from the Alabama Public Service Commission to acquire this generating unit.

The remaining projected firm capacity purchases for both areas are from a combination of utility and independent power producers. Details for these other purchases, including the annual total capacity values, are presented in Chapter I in Tables I.A.3.2, I.A.3.3, I.B.3.2, and I.B.3.3. These purchased firm capacity amounts were incorporated in the resource planning work that led to the resource plan presented in this document.

The third set of assumptions involves a projection of the amount of incremental DSM that FPL and Gulf anticipate implementing annually over the ten-year reporting period of 2020 through 2029 for this Site Plan. In the 4th Quarter of 2019, the Florida Public Service Commission (FPSC) set DSM Goals for FPL, Gulf, and other Florida utilities that addressed the years 2020 through 2024. The annual amounts of Summer MW reduction, Winter MW reduction, and energy (MWh) reduction for the FPL and Gulf areas detailed in the FPSC's DSM Goal's order (Order No. PSC-2019-0509-FOF-EG) through 2024 are accounted for in the resource plan presented in this Site Plan. For the years 2025 through 2029, the annual DSM levels proposed in the DSM Goals docket separately by FPL and Gulf – because they were projected to be cost-effective - are also accounted for in the resource plan presented in this Site Plan. Those annual amounts are shown in Schedules 3.1, 3.2, and 3.3 in Chapter II.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

FPL's resource planning process applies these key assumptions, plus the other updated information described above, in the first fundamental step: determining the magnitude and timing of future resource needs. This determination is accomplished through system reliability analyses. Until 2014, FPL's reliability analyses were based on dual planning criteria, including a minimum peak-period total reserve margin (TRM) of 20% (FPL applies this criterion to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both criteria are commonly used throughout the utility industry. Beginning in 2014, FPL began utilizing a third reliability criterion: a 10% generation-only reserve margin (GRM).

Until the acquisition of Gulf by NextEra Energy in January 2019, the reliability criteria used for Gulf was determined by analyses of the entire Southern Company system of which Gulf was a part. It is projected that Southern Company will continue to operate Gulf's generating units as part of its system until the new North Florida Resiliency Connection transmission line is in-service by the end of 2021. At that time, FPL will begin to operate Gulf's generating units as well as FPL's units as part of a single, integrated electrical system. In addition, the generation-based reliability of the Gulf area will be evaluated, and the area planned, using FPL's current three reliability criteria described above.

These reliability criteria utilize two basic types of methodologies: deterministic and probabilistic. The calculation of excess firm capacity at the annual system peaks (reserve margin) is a common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements, such as the impact of individual unit failures. For example, two 50 MW units that can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit that also can be counted on to run 90% of the time. Probabilistic methods can also account for the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system, and a number of them are used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP), which FPL's resource planning group utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (*i.e.*, a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as “the number of days per year” that the system firm load could not be met. The standard for LOLP used by FPL’s resource planning group, is a maximum of 0.1 day per year which is commonly accepted throughout the industry. This analysis requires a more complicated calculation methodology than the reserve margin analysis. LOLP analyses are typically carried out using computer software models, such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

In 2010, FPL’s integrated resource planning work examined a then-projected fundamental change in FPL’s resource plans. This change was a significant shift in the mix of generation and DSM resources that could result in FPL becoming increasingly reliant on DSM resources, rather than generation resources, to maintain system reliability. As discussed in several subsequent FPL Site Plans, extensive analyses examined this shift from a system reliability perspective.

In these analyses, FPL developed a key new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, to derive another useful version of a reserve margin calculation. The resulting GRM value provides an indication of the respective roles that DSM and generation are projected to play each year as FPL maintains its 20% Summer and Winter total reserve margins (which account for both generation and DSM resources).

These analyses examined the two types of resources, DSM and Supply options, from both an operational and a resource planning perspective. Based on these analyses, FPL concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin value. In other words, it matters what resources are used to meet a reserve margin criterion such as 20%. Therefore, in 2014 FPL implemented a minimum GRM criterion of 10% as a third reliability criterion in its resource planning process.

The 10% minimum Summer and Winter GRM criterion augments the other two reliability criteria that FPL's resource planning group uses: the 20% TRM criterion for Summer and Winter and the 0.1 day/year LOLP criterion. All three reliability criteria are useful to identify the timing and magnitude of the resource need because of the different perspectives the three criteria provide. In addition, the GRM criterion is particularly useful in providing direction regarding the mix of generation (combined cycle, solar, etc.) and DSM resources that should be added to maintain and enhance system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of Projected Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in certain key characteristics may be conducted to determine what type of new capacity option appears to be the most competitive on FPL's system. Preliminary analyses also can help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL's resource planning group typically utilizes a production cost model, a Fixed Cost Spreadsheet, and/or an optimization model to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model, which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. A years-to-payback screening test based on a two-year payback criterion is also used in the preliminary economic screening of individual DSM measures and programs in order to minimize the probability of paying incentives to customers who would have implemented a DSM measure anyway without a utility incentive (*i.e.*, free riders). Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL typically uses two additional models. One is a proprietary non-linear programming (NLP) model that is used to analyze the potential for lowering system peak loads through additional load management/demand response capability. The other model that is utilized is a proprietary linear programming (LP) model with which DSM portfolios are developed.

The next step is typically to "package" the individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses into different resource plans that are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (*i.e.*, resource plans) of a magnitude and timing necessary to meet the projected resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental Steps 1 and 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans that each meet the magnitude and timing of projected resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the utility system from the competing resource options/resource plans. FPL's resource planning group typically utilizes the UPLAN production cost model and a Fixed Cost Spreadsheet, and/or the EGEAS or AURORA optimization models, to perform the system economic analyses of resource plans. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on electricity rate levels, with the general objective of minimizing the projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of the impacts of competing resource plans on both electricity rates and system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

FPL's resource planning group also includes other factors in its evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative but non-economic terms, such as percentages, tons, etc., rather than in terms of dollars. These factors are often referred to as "system concerns or factors," which include (but are not limited to) maintaining/enhancing fuel diversity and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida region of FPL's area that consists of Miami-Dade and Broward counties. In conducting the evaluations needed to determine which resource options and resource plans are best for the utility system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These and other factors are discussed later in this chapter in section III.C.

Step 4: Finalizing the Current Resource Plan

The results of the previous three fundamental steps are typically used to develop a new or updated resource plan. The current resource plan presented in this 2020 Site Plan is summarized in the following section.

III.B. Projected Incremental Resource Changes in the Resource Plan

The projection of major changes in the current resource plan for the FPL and Gulf areas, including both utility-owned generation and PPAs, for the years 2020 through 2029 is summarized in Table ES-1 in the Executive Summary. The changes are presented in terms of Summer firm capacity values. Although this table does not specifically identify the impacts of projected DSM additions on projected resource needs and the resource plan, the projected DSM additions are consistent with the recent DSM Goals order regarding DSM Goals for both FPL and Gulf through the year 2024. In addition, projected cost-effective amounts of DSM for the years 2025 through 2029 are also assumed. Thus, DSM impacts are fully accounted for in the resource plan in this Site Plan.

A summary of some of the larger resource additions/retirements for both systems/areas include, but are not necessarily limited to, those listed below (in approximate chronological order):

<u>For FPL's system/area:</u>

- New solar (PV) additions from 2020 through 2029 of approximately 7,300 MW;
- Capacity upgrades at a number of FPL's existing CC units through 2026;
- Retirement of FPL's ownership portion (approximately 630 MW) of the Scherer 4 coal unit by January 2022;

- A 409 MW battery facility at the Manatee plant site, plus two 30 MW battery storage facilities at different sites, by the beginning of 2022; and,
- The modernization of the existing Lauderdale power plant site in mid-2022 with the new DBEC CC Unit 7.

For Gulf's system/area:

- New solar (PV) additions from 2020 through 2024 of approximately 1,560 MW;
- Capacity upgrades (two) of the existing Lansing Smith Unit 3 CC, with installation for the first upgrade completed in 2019 with testing and tuning in the Spring of 2020, then a planned second upgrade in 2024;
- Conversion from coal-fueled to natural gas-fueled at Crist Units 6 & 7 in 2020;
- A new transmission line between FPL and Gulf by the beginning of 2022 enabling a bidirectional transfer capability between the two areas of 850 MW;
- Four new CTs at the Crist plant site by the beginning of 2022;
- Expiration (as per the contract) of 855 MW from the Shell PPA in May, 2023;
- The retirement of Gulf's ownership portion of the coal-fueled Daniels Units 1 & 2 by the beginning of 2024; and,
- Approximately 700 MW of battery storage in 2028 and 2029.

FPL notes that, with the exception of certain of the resource additions and retirements listed above in the earlier years of the 2020 through 2029 time period addressed in this 2020 Site Plan, final decisions on other resource options shown in this Site Plan are not needed at this time, nor have yet been made. This is particularly relevant to resource additions shown for years increasingly further out in the 10-year reporting period. Consequently, those resource additions are more prone to future change.

III.C Discussion of the Resource Plan and Issues Impacting Resource Planning Work

In considering the resource plan presented in this Site Plan, it is useful to note that there are at least six (6) significant factors that either influenced the current resource plan or which may result in future changes. These factors are discussed below (in no particular order).

1. **Maintaining a Balance Between Load and Generation in Southeastern Florida:**
   An imbalance exists between regionally installed generation and regional peak load in Southeastern Florida (Miami-Dade and Broward counties). As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by importing energy through the transmission system from generating

units located outside the region, operating less efficient generating units located in Southeastern Florida out of economic dispatch, or a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, additional installed generating capacity and/or load reduction in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location in or adjacent to Southeastern Florida, at least five relatively recent capacity additions (Turkey Point Unit 5, West County Energy Center Units 1, 2, & 3, and the modernization of the Port Everglades plant) were determined to be the most cost-effective options to meet FPL's then projected capacity needs. In addition, FPL has added increased capacity at its existing two nuclear units at Turkey Point as part of the nuclear capacity uprates project.

The balance between load and generation in the Southeastern Florida region was further enhanced by decisions to proceed with two other projects. First, the Corbett-Sugar-Quarry (CSQ) transmission line was added in mid-2019. This new line significantly increased FPL's ability to import capacity and energy into the region from generators located outside of the region. Second, the modernization of the existing Lauderdale plant site, which will result in an additional 279 MW of generation capacity in Southeastern Florida from the new DBEC Unit 7 in 2022, will significantly assist in maintaining and enhancing a balance between load and generation in this important region.

2. Maintaining/Enhancing System Fuel Diversity:

In 2019, FPL used natural gas to generate approximately 75% of the total electricity it delivered to its customers. By 2029, due largely to significant solar additions, the percentage of electricity generated by natural gas for the single integrated system is projected to decrease to approximately 62% based on the resource plan presented in this Site Plan. Due to this still significant reliance on natural gas, as well as evolving environmental regulations, opportunities to economically maintain and enhance fuel diversity are continually sought, both in regard to type of fuel and fuel delivery, with due consideration given to system economics.

In 2007, following express direction by the FPSC, FPL sought approval from the FPSC to add two new advanced technology coal units to its system in 2013 and 2014, respectively. However, these units were not approved. Since that time, coal units have ceased to be a viable generation option for a number of reasons which include: (i) environmental regulations regarding coal units, (ii) increased availability of natural gas, (iii) much lower forecasted costs for natural gas, and (iv) increased economic competitiveness of solar and battery storage. Consequently, FPL does not believe that new advanced technology coal units are currently viable fuel diversity enhancement options in Florida at this time.

Therefore, FPL has focused on: (i) cost-effectively adding solar energy and nuclear energy generation to enhance fuel diversity, (ii) diversifying the sources of natural gas, (iii) diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and (iv) using natural gas more efficiently.

Solar Energy: Assuming that annual additions of PV will be cost-effective from 2020-on, this 2020 Site Plan projects that FPL will have a total of approximately 10,000 MW of PV generation by the end of 2029. Such a level of PV generation would represent about 33% of FPL's and Gulf's current total installed generation (MW). However, the impact of PV contribution in terms of actual energy produced (MWh) is smaller. Because solar energy can only be generated during daylight hours, and is impacted by clouds, rain, etc., PV has a relatively low capacity factor (approximately 26% to 30%) in the state of Florida. As a result, FPL's solar additions would be projected to supply approximately 16% of the total energy (MWh) delivered in 2029 in the two areas (as shown in Schedule 6.2 later in this chapter).[10]

Based on the resource plan presented in this 2020 Site Plan, it is projected that the cleanest energy sources -- low-emission natural gas, zero-emission nuclear, zero-emission wind, and zero-emission solar – will provide approximately 99% of all energy produced in the single, merged system in 2029 with zero-emission nuclear, wind, and solar alone providing approximately 37% of all energy produced by the system in 2029.

Nuclear Energy: In 2008, the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized the company to recover project-related expenditures that were approved as a result of annual nuclear cost recovery filings. FPL successfully completed this nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity was delivered by the project, which represents an increase of approximately 30% more incremental capacity than was originally forecasted when the project began. FPL's customers are benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

[10] As a rule of thumb, each 500 MW of PV added will account for slightly less than 1% of total energy delivered on the single, integrated system.

In June 2009, FPL began work to obtain all of the licenses, permits, and approvals that are necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units for as long as 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The Combined Operating Licenses (COL) for the prospective new Turkey Point Units 6 & 7 were granted by the Nuclear Regulatory Commission (NRC) in April 2018. FPL has paused in its determination of whether to seek FPSC approval to move forward with construction of the new nuclear units. FPL intends to incorporate into any such assessment the construction experience of two nuclear units currently being constructed by Georgia Power at its Vogtle site, and similar units being developed in China. As a result, the earliest possible in-service dates for Turkey Point 6 & 7 are beyond the 2020 through 2029 time period addressed in this docket.

In addition, on January 30, 2018, FPL filed a request with the NRC for a Subsequent License Renewal (SLR) for FPL's existing Turkey Point nuclear Units 3 & 4. The SLR requested approval to extend the operating licenses for these two nuclear units by 20 years from the license expiration dates in 2032 and 2033, respectively. The NRC approved the SLR in December 2019. As a result, FPL assumes that these two nuclear units will continue operating into the early 2050s, providing firm capacity into the important load center of Miami-Dade and Broward Counties, as well as zero-emission baseload energy.

Nuclear capacity remains an important consideration in resource planning work, and this Site Plan continues to present the Turkey Point site as a Preferred Site for the new and/or continuing nuclear capacity and energy.

<u>Natural gas sourcing and delivery:</u> In 2013, the FPSC approved FPL's contracts to bring more natural gas into FPL's service territory through a third natural gas pipeline system into Florida. The process by the pipeline companies to obtain approval from the Federal Energy Regulatory Commission (FERC) for the new pipeline system, consisting of the Sabal Trail and Florida Southeast Connection pipelines, culminated in receiving a FERC certificate of approval on February 2, 2016. The new pipeline system has been constructed and is now in service. This pipeline is necessary to fuel the FPSC-approved Okeechobee CC unit. The new pipeline system utilizes an independent route that will result in a more reliable, economic, and diverse natural gas supply for FPL customers and the State of Florida.

Using natural gas more efficiently: FPL has sought ways to utilize natural gas more efficiently for a number of years. In 2008, FPL received approval from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units, which replaced the former steam generating units on each of those sites. The Cape Canaveral modernization went into service in April 2013, and the Riviera Beach modernization entered service in April 2014. On April 9, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site. That new generating unit went into service on April 1, 2016.

Similarly, the modernization of the Lauderdale site in 2022 will also enhance FPL's ability to utilize natural gas more efficiently. The modernization project has begun with the recent retirement of two older, relatively fuel-inefficient generating units, Lauderdale Units 4 & 5. In 2022, a new fuel-efficient CC unit will be added at the same site: DBEC Unit 7. Part of the decision to proceed with the modernization of the Lauderdale site was the projection that the total amount of natural gas that will be used on FPL's system will be reduced with the new CC unit compared to what the usage would have been if the two older units had continued to operate.

Addition of Gulf Assets**:** Gulf Power (Gulf) currently owns two generating plants in the Florida Panhandle. Plant Crist, located in Pensacola, currently runs on coal with limited access to natural gas. Plant Smith, located near Panama City, is a CC natural gas plant. Gulf has access to gas transportation capacity on the Gulf South Pipeline Company, LP (Gulf South) and the Florida Gas Transmission Company, LLC (FGT) pipelines to serve these plants. Gulf is completing uprates at Plant Smith's Unit 3 to increase the output of the unit. Gulf is currently in the process of converting Plant Crist Units 6 & 7 to allow utilization of natural gas which will be delivered via a new plant lateral connecting Plant Crist to the FGT pipeline. This conversion is projected to be completed in the Summer of 2020. Gulf will also be adding four new CTs at Plant Crist in late 2021 that will have the capability to burn either natural gas or ultra-low sulfur distillate (ULSD) fuel oil.

In the future, FPL's resource planning group will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, efforts are also being made to maintain the ability to utilize ULSD oil at existing units that have that capability. In addition, the new CTs that FPL installed at its existing Lauderdale and Fort Myers sites in 2016, which replaced older GT units that were retired, have the capability to burn either natural gas or ULSD fuel oil.

3. Maintaining a Balance Between Generation and DSM Resources for System Reliability:

As mentioned earlier in Section III. A, FPL utilizes a 10% Generation-Only Reserve Margin (GRM) to ensure that system reliability is not negatively affected by an overreliance on non-generation resources. This GRM reliability criterion was developed as a result of extensive analyses – which have been described in detail in prior FPL Site Plans – of FPL's system from both resource planning and system operations perspectives. The potential for overreliance upon non-generating resources for system reliability remains an important resource planning issue for the FPL and Gulf areas and is one that will continue to be examined in ongoing resource planning work.

4. The Significant Impacts of Federal and State Energy-Efficiency Codes and Standards:

As discussed in Chapter II, the load forecasts for both the FPL and Gulf areas include projected impacts from federal and state energy-efficiency codes and standards. The magnitude of energy efficiency that is currently projected to be delivered to customers of the single, integrated system through these codes and standards is significant.

Current projections are that a cumulative Summer peak reduction impact of 5,732 MW, from these codes and standards beginning in 2005 (the year the National Energy Policy Act was enacted) and extending through 2029 (*i.e.*, the last year in the 2020 through 2029 reporting time period for this Site Plan), will occur compared to what the projected load would have been without the codes and standards. The projected incremental Summer MW impact from these codes and standards during the 2020 through 2029 reporting period of this Site Plan is the equivalent of an approximate 19% reduction compared to what the projected load would have been without the codes and standards. In regard to energy, the cumulative reduction attributed to the impact of the codes and standards from 2005 to 2029 is projected to reach 6,082 GWh since 2005. Included in this projection is a reduction of approximately 4% during the 2020 through 2029 reporting period. All of these projections show the significant impact of these energy-efficiency codes and standards.

In addition to lowering the load forecast from what it otherwise would have been, and thus serving to lower projected load and resource needs, this projection of efficiency from the codes and standards also affects resource planning in another way: it lowers the potential for utility DSM programs to cost-effectively deliver energy efficiency. This effect was taken into account by the FPSC when it set DSM Goals in 2014. This fact was also prominently discussed in the 2019 DSM Goals docket in which DSM Goals were set for the years 2020 through 2024.

5. **The trends of decreasing costs for fuel, decreasing costs for new generating units, and increasing fuel efficiency of new generating units:**

There are a number of factors that drive FPL's system costs. Three of the most important of these are: (i) forecasted natural gas costs, (ii) projected costs for new generating units, and (iii) the efficiency with which FPL's generating units convert fuel into electricity. When comparing forecasts of these factors over at least the last 5 years, the trends for each of these factors is in a direction that results in lower system costs for FPL's customers. For example, when comparing the 2015 forecasted cost for natural gas for the year 2020 with the current (2020) forecasted cost for 2020, there has been more than a 55% decrease in natural gas costs. An even greater reduction in CO_2 compliance costs for 2020 occurred between the 2015 and current forecast. In addition, in regard to the fuel efficiency of FPL's generating units, the amount of natural gas (measured in mmBTU of natural gas needed to produce a kWh of electricity) declined from 7,376 in 2015 to approximately 6,752 today. This improvement in fuel efficiency is truly significant, especially when considering the approximately 20,000 MW of gas-fueled generation on FPL's system.

These trends of steadily lowering of key components of FPL's system costs are very beneficial to FPL's customers because they help to lower FPL's electric rates[11].

6. **Projected changes in CO_2 regulation and associated compliance costs:**

Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has included projected compliance costs for CO_2 emissions in its resource planning work. However, there always has been an unavoidable level of uncertainty regarding the timing and magnitude of the cost impacts of the potential regulation/legislation. The forecast of potential CO_2 compliance costs that FPL used in its 2019 resource planning work is lower than forecasts that had been used in prior years. In 2020, the new forecast of compliance costs is higher than the 2019 forecast but remains relatively low by historical standards.

[11] However, because the potential benefits of utility demand-side management (DSM) programs are based on DSM's ability to avoid certain system costs, the trend of steadily decreasing FPL system costs automatically results in a significant lowering of the cost-effectiveness of utility DSM.

III.D Demand Side Management (DSM)

FPL has sought and implemented cost-effective DSM programs since 1978, and cost-effective DSM has been a key focus of FPL's resource planning work for more than 40 years. During that time, FPL's DSM programs have included many energy efficiency and load management programs and initiatives. Similarly, Gulf has also steadily pursued cost-effective DSM for decades.

DSM Goals were set for FPL, Gulf, and other Florida utilities in November 2019. As discussed in FPL's testimony in the 2019 DSM Goals filing that led to these Goals being set, there were several important market forces affecting the feasibility and cost-effectiveness of utility DSM programs. The first of these is the growing impact of federal and state energy-efficiency codes and standards. As discussed first in Chapter II, and earlier in Section III.C above, the projected incremental impacts of these energy-efficiency codes and standards during the 2020 through 2029 time period has significantly lowered FPL's projected load and resource needs. In addition, these energy-efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs.

The second market force discussed in FPL's DSM Goals Testimony is FPL's lower generating costs with which DSM must compete. There are several reasons for these lower generating costs. One of these is that, as fuel costs are lowered, the benefit that is realized by each kWh of energy reduced by DSM is also lowered. In other words, the benefit from DSM's kWh reductions has been reduced from what it had been when Florida previously established DSM Goals. For example, from 2015 to 2020, projected fuel costs in $ per mmBTU for the year 2020 have decreased from $5.15 to $2.31, a percentage decrease of 55%. These lower forecasted natural gas costs are very beneficial for FPL's customers because they result in lower fuel costs and lower electric rates. At the same time, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective than it was in the past.

Another reason for the lower generating costs and the resultant decline in the cost-effectiveness of utility DSM on the FPL system is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily become more efficient in regard to its ability to generate electricity using less fossil fuel. For example, the FPL system is projected to use almost 30**%** less fossil fuel to generate a MWh in 2020 than it did in 2001. Again, this is very good for FPL's customers because it helps to significantly lower fuel costs and electric rates. However, the improvements in generating system efficiency affect DSM cost-effectiveness in much the same way as lower forecasted fuel costs: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus further lowering potential DSM benefits and DSM cost-effectiveness.

These market forces that result in lower fuel and new generation costs for utility customers, and lower avoided costs for utility DSM programs, was a topic that was prominently discussed when new DSM Goals for the years 2020 through 2024 were set for FPL, Gulf, and other Florida utilities by the FPSC in the 4th Quarter of 2019. Consideration of these market forces, and of the effects of energy-efficiency codes and standards, were undoubtedly factors helping lead the FPSC to decide to maintain the DSM Goals at the same levels that had been set five years earlier, and to resist efforts to greatly increase DSM Goals for the Florida utilities and their customers.

For resource planning purposes, the DSM Goals set for both FPL and Gulf through 2024 are accounted for in this Site Plan. In addition, the annual DSM levels proposed separately by FPL and Gulf for the years 2025 through 2029 in the DSM Goals docket are accounted for in this Site Plan because these annual levels of DSM were projected to be cost-effective.

In February 2020, FPL and Gulf submitted to the FPSC their respective DSM Plans with which they will strive to meet the DSM Goals for 2020 through 2024. A summary of the programs for both FPL and Gulf is provided below. The FPSC is expected to determine the suitability of the respective DSM Plans later in 2020.

DSM Programs and Research & Development Efforts In FPL's Proposed DSM Plan

1. **Residential Home Energy Survey (HES)**
   This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The HES is also used to identify potential candidates for other FPL DSM programs.

2. **Residential Load Management (On Call)**
   This program allows FPL to turn off certain customer-selected appliances using FPL-installed equipment during periods of extreme demand, capacity shortages, system emergencies, or for system frequency regulation.

3. Residential Air Conditioning

This program encourages customers to install high-efficiency central air-conditioning systems.

4. Residential Ceiling Insulation

This program encourages customers to improve their home's thermal efficiency.

5. Residential New Construction (BuildSmart®)

This program encourages builders and developers to design and construct new homes to achieve BuildSmart® certification and move towards ENERGY STAR® qualifications.

6. Residential Low Income

This program assists low income customers through FPL-conducted Energy Retrofits and state Weatherization Assistance Provider (WAP) agencies.

7. Business Energy Evaluation (BEE)

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The BEE is also used to identify potential candidates for other FPL DSM programs.

8. Commercial/Industrial Demand Reduction (CDR)

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies.

9. Commercial/Industrial Load Control (CILC)

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages or system emergencies. It was closed to new participants as of December 31, 2000.

10. Business On Call

This program allows FPL to turn off customers' direct expansion central electric air conditioning units using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

11. Business Heating, Ventilating and Air Conditioning (HVAC)

This program encourages customers to install high-efficiency HVAC systems.

12. Business Lighting

This program encourages customers to install high-efficiency lighting systems.

13. Business Custom Incentive (BCI)

This program encourages customers to install unique high-efficiency technologies not covered by other FPL DSM programs.

14. Conservation Research & Development (CRD) Project

This project consists of research studies designed to: identify new energy-efficient technologies; evaluate and quantify their impacts on energy, demand and customers; and, where appropriate and cost-effective, incorporate an emerging technology into a DSM program.

DSM Programs and Research & Development Efforts In Gulf's Proposed DSM Plan

1. Residential Energy Audit

This program educates customers on energy efficiency through energy conservation advice and information that encourages the implementation of efficiency measures and behaviors resulting in energy and utility bill savings. The Residential Energy Audit program is also used to identify potential candidates for other Gulf Power DSM programs.

2. *Energy Select*

This program is designed to provide the customer with a means of conveniently and automatically controlling and monitoring energy purchases in responses to prices that vary during the day and by season in relation to Gulf's cost of producing or purchasing energy. The *Energy Select* system includes field units utilizing a communication gateway, major appliance load control relays, and a programmable thermostat, all operating at the customer's home.

3. Community Energy Saver Program

This program is designed to assist low-income families with energy costs through the direct installation of conservation measures at no cost to them. The program also educates families on energy efficiency techniques and behavioral changes to help control their energy use and reduce their utility operating costs.

4. **Residential Ceiling Insulation**

   This program encourages customers to improve their home's thermal efficiency.

5. **Residential Heat Pump**

   This program encourages customers to install high-efficiency heat pump systems.

6. **Residential Variable Speed Pool Pump**

   This program encourages customers to install high-efficiency variable speed pool pump systems.

7. **Commercial/Industrial Energy Survey**

   This program educates customers on energy efficiency and encourages them to participate in applicable DSM programs and/or implement other recommended actions not included as part of Gulf Business programs.

8. **Business Heating, Ventilating and Air Conditioning (HVAC)**

   This program encourages customers to install high-efficiency HVAC systems.

9. **Commercial Curtailable Load Program**

   This program allows Gulf to request curtailment of customer loads with a minimum commitment of 4,000 kW of Non-Firm Demand. The program will be closed to new participants when the total contracted Non-Firm Demand reaches 50 MW.

10. **Commercial/Industrial Custom Incentive**

    This program is designed to establish the ability to offer advanced energy services and energy efficient end-user equipment (including comprehensive audits, design, and construction of energy conservation projects) not offered through other programs to Commercial or Industrial customers.

11. **Conservation Demonstration & Development**

    The program is designed to serve as an umbrella program for the identification, evaluation, demonstration, data collection and development of new or emerging end-use technologies.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's and Gulf's retail and wholesale customers. The following table presents the proposed future additions of 230 kV and above bulk transmission lines that must be certified under the Transmission Line Siting Act (TLSA) for the FPL and Gulf areas. There is one such line in FPL's area, but none in Gulf's area, for this 10-year reporting period.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	Levee 1/	Midway	150	2030	500	2598

1/ Final order certifying the corridor was issued in April 1990. Construction of 138 miles is complete and in-service. Another phase of the project will utilize the remaining 12 mile section of the Levee-Midway corridor and will bring a second 500 kV line to feed Conservation 500/230 kV substation. The second Conservation 500 kV line is currently projected to be built no earlier than 2030 with the month in which the line would go into service unknown at this time.

In addition, there will be transmission facilities needed to connect several projected generation capacity additions to the system transmission grid in both the FPL and Gulf areas. These transmission facilities are described on the following pages. Other generation capacity additions, such as Dania Beach Clean Energy Center Unit 7 in mid-2022, will not require new transmission lines. Sites for longer term additions, such as projected PV additions for 2022-on, have not yet been definitely determined so no transmission analyses for these additions have been performed.

III.E.1 Transmission Facilities for the Hibiscus Solar Energy Center in Palm Beach County

The work required to connect the approximate 74.5 MW (nameplate, AC) Hibiscus Solar Energy Center in Palm Beach County in the 2nd Quarter of 2020 as part of the 2020 SoBRA PV additions is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Minto) on the project site approximately 1 mile west of FPL's Westlake substation on the Ranch-Corbett 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Minto 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Westlake-Corbett section of the Corbett-Ranch 230 kV line into Minto substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.2 Transmission Facilities for the Okeechobee Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Okeechobee Solar Energy Center in Okeechobee County in the 2nd Quarter of 2020 as part of the 2020 SoBRA PV additions is projected to be:

I. **Substation:** None. Solar PV project to be connected to low-side of Okeechobee Clean Energy Center Combustion Turbine Generator Step-up transformer inside the existing plant, which is connected to Fort Drum 500 kV Substation.

II. **Transmission:** None. Solar PV project to be connected to low-side of Okeechobee Clean Energy Center Combustion Turbine Generator Step-up transformer inside the existing plant, which is connected to Fort Drum 500 kV Substation.

III.E.3 Transmission Facilities for the Southfork Solar Energy Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Southfork Solar Energy Center in Manatee County in the 2nd Quarter of 2020 as part of the 2020 SoBRA PV additions is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation ("Duette") on the project site on the FPL Manatee-Keentown 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Duette 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Manatee-Keentown 230 kV line into Duette substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.4 Transmission Facilities for the Echo River Solar Energy Center in Suwannee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Echo River Solar Energy Center in Suwannee County in the 2nd Quarter of 2020 as part of the 2020 SoBRA PV additions is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 115 kV substation (Hogan) on the project site approximately 2.6 miles west of the FPL Wellborn substation on the Suwannee (Duke Energy Florida DEF) – Columbia (FPL) 115 kV line.
2. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Hogan 115 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Wellborn-Live Oak section of the Suwannee (Duke Energy) – Columbia (FPL) 115 kV line into Hogan substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.5 Transmission Facilities for the Lakeside Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Lakeside Solar Energy Center in Okeechobee County in the 4th Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Nubbin) on the project site on the FPL Martin-Sherman 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Nubbin 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Martin-Sherman 230 kV line into Nubbin substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.6 Transmission Facilities for the Trailside Solar Energy Center in St. Johns County

The work required to connect the approximate 74.5 MW (nameplate, AC) Trailside Solar Energy Center in St. Johns County in the 4th Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 115 kV substation (Moccasin) on the project site on the FPL Elkton-St. Johns section of the Putnam-St. Johns 115 kV line.
2. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Moccasin 115 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Elkton-St. Johns section of the Putnam-St. Johns 115 kV line into Moccasin substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.7 Transmission Facilities for the Union Springs Solar Energy Center in Union County

The work required to connect the approximate 74.5 MW (nameplate, AC) Union Springs Solar Energy Center in Union County in the 4^{th} Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 115 kV substation (Plum) on the project site approximately 0.1 mile from the FPL Bradford-Lake Butler section of the Raven-Bradford 115 kV line.
2. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Plum 115 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the FPL Bradford-Lake Butler section of the Raven-Bradford 115 kV line into Plum substation.
2. No additional upgrades are expected to be necessary at this time

III.E.8 Transmission Facilities for the Magnolia Springs Solar Energy Center in Clay County

The work required to connect the approximate 74.5 MW (nameplate, AC) Magnolia Springs Solar Energy Center in Clay County in the 4th Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Leno) on the project site approximately 0.1 mile from the Titanium-Green Cove Springs section of the Seminole Plant-Springbank 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Leno 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Titanium-Green Cove Springs section of the Seminole Plant-Springbank 230 kV line into Leno substation on the project site.
2. No additional upgrades are expected to be necessary at this time

III.E.9 Transmission Facilities for the Egret Solar Energy Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Egret Solar Energy Center in Baker County in the 4th Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Claude) on the project site approximately 2 miles from the FPL Duval-Raven 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Claude 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Duval-Raven 230 kV line into Claude substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.10 Transmission Facilities for the Nassau Solar Energy Center in Nassau County

The work required to connect the approximate 74.5 MW (nameplate, AC) Nassau Solar Energy Center in Nassau County in the 4th Quarter of 2020 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Crawford) on the project site on the FPL Duval-West Nassau (Georgia Transmission Company, "GTC") section of the Duval-Yulee 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Crawford 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Duval-West Nassau (GTC) section of the Duval-Yulee 230 kV line into Crawford substation (approximately 1 mile).
2. No additional upgrades are expected to be necessary at this time.

III.E.11 Transmission Facilities for the Pelican Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Pelican Solar Energy Center in St. Lucie County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new 230 kV substation (Morrow) on the project site.
2. Add one 230 kV line switch at Morrow for string bus to Eldora substation
3. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
4. Construct 34.5 kV bus to connect the PV array to Morrow 230 kV Substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Construct approximately 1.25 miles string bus from Eldora 230 kV to Morrow substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.12 Transmission Facilities for the Palm Bay Solar Energy Center in Brevard County

The work required to connect the approximate 74.5 MW (nameplate, AC) Palm Bay Solar Energy Center in Brevard County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Hayward) on the project site on the FPL Glendale-Hield section of the Midway-Malabar 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Hayward 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Glendale-Hield section of the Midway-Malabar 230 kV line into Hayward substation (approximately 2.5 miles).
2. No additional upgrades are expected to be necessary at this time.

III.E.13 Transmission Facilities for the Discovery Solar Energy Center in Brevard County

The work required to connect the approximate 74.5 MW (nameplate, AC) Discovery Solar Energy Center in Brevard County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 115 kV substation (Rocket) on the project site on the FPL C5-Barna 115 kV line.
2. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to Rocket 115 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the C5-Barna 115 kV line into Rocket substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.14 Transmission Facilities for the Orange Blossom Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Orange Blossom Solar Energy Center in Indian River County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new 230 kV substation (Finca) on the project site.
2. Add one 230 kV line switch at Finca bifurcating Eldora-Heritage 230 kV line approximately 1 mile from Eldora
3. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
4. Construct 34.5 kV bus to connect the PV array to Finca 230 kV Substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Bifurcate Eldora-Heritage 230 kV line approximately 1 mile from Eldora at Finca substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.15 Transmission Facilities for the Sabal Palm Solar Energy Center in Palm Beach County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sabal Palm Solar Energy Center in Palm Beach County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new 230 kV substation (Costa) on the project site.
2. Add one 230 kV line switch at Costa for string bus to Minto substation
3. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
4. Construct 34.5 kV bus to connect the PV array to Costa 230 kV Substation.
5. Add one 230 kV breaker to close ring bus at Minto substation
6. Add relays and other protective equipment.
7. Breaker replacements: None

II. Transmission:

1. Construct approximately 1.5 miles string bus from Minto 230 kV to Costa substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.16 Transmission Facilities for the Fort Drum Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Fort Drum Solar Energy Center in Okeechobee County in the 1st Quarter of 2021 is projected to be:

I. Substation:

None. Solar PV project to be connected to low-side of Okeechobee Clean Energy Center Combustion Turbine Generator Step-up transformer inside the existing plant, which is connected to Fort Drum 500 kV Substation.

II. Transmission:

None. Solar PV project to be connected to low-side of Okeechobee Clean Energy Center Combustion Turbine Generator Step-up transformer inside the existing plant, which is connected to Fort Drum 500 kV Substation.

III.E.17 Transmission Facilities for the Rodeo Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Rodeo Solar Energy Center in DeSoto County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new 230 kV substation (Karson) on the project site.
2. Add one 230 kV line switch at new substation to connect to Gleam substation (Cattle Ranch Solar Energy Center)
3. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
4. Construct 34.5 kV bus to connect the PV array to new 230 kV Substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Connect new substation line switch via string bus to Gleam substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.18 Transmission Facilities for the Willow Solar Energy Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Willow Solar Energy Center in Manatee County in the 1st Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Coachwhip) on the project site on the FPL Sunshine-Keentown 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
3. Construct 34.5 kV bus to connect the PV array to new Coachwhip 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Sunshine-Keentown 230 kV line into new Coachwhip substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.19 Transmission Facilities for Manatee Energy Storage Center in Manatee County

The approximately 409 MW battery storage addition that will be sited in Manatee County with a projected in-service date of late 2021 does not require any new offsite transmission lines.

III.E.20 Transmission Facilities for Sunshine Gateway Energy Storage addition in Columbia County

The 30 MW battery energy storage facility projected to be in-service in late 2021 that will be added to the existing Sunshine Gateway Solar Energy Center in Columbia County does not require any new offsite transmission lines[12].

[12] This battery storage facility is currently projected to be a 30 MW facility. However, on-going analyses may result in an increase to approximately 75 MW.

III.E.21 Transmission Facilities for Echo River Energy Storage addition in Suwannee County

The 30 MW battery energy storage facility projected to be in-service in late 2021 that will be added to the Echo River Solar Energy Center in Suwannee County does not require any new offsite transmission lines[13].

[13] This battery storage facility is currently projected to be a 30 MW facility. However, on-going analyses may result in an increase to approximately 75 MW.

III.E.22 Transmission Facilities for the Lauderdale Plant Modernization (Dania Beach Clean Energy Center Unit 7) in Broward County

The Lauderdale Modernization project (Dania Beach Clean Energy Center Unit 7) that is projected to be completed by mid-2022 does not require any new offsite transmission lines.

III.E.23 Transmission Facilities for the Blue Springs Solar Energy Center in Jackson County

The work required to connect the approximate 74.5 MW (nameplate, AC) Blue Springs Solar Energy Center in Jackson County in the 4th Quarter of 2021 is projected to be:

I. Substation:

a. Construct a new single bus, two (2) breaker 115 kV substation (Americus) on the project site, approximately 2 miles from the Cypress – Chipola section of the Gulf Marianna – West Grand Ridge 115 kV line.
b. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array.
c. Construct 34.5 kV bus to connect the PV array to Americus 115 kV Substation.
d. Add relays and other protective equipment.
e. Breaker replacements: None

II. Transmission:

a. Loop the Cypress – Chipola section of the Gulf Marianna – West Grand Ridge 115 kV line into Americus substation.
b. No additional upgrades are expected to be necessary at this time.

III.E.24 Transmission Facilities for the Chautauqua Solar Energy Center in Walton County

The work required to connect the approximate 74.5 MW (nameplate, AC) Chautauqua Solar Energy Center in Walton County in the 4th Quarter of 2021 is projected to be:

I. Substation:

1. Construct a new 230 kV substation ("Liddie") on the project site.
2. Add two 230 kV line switches on the Shoal River – Samson 230kV line at Liddie Substation
3. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
4. Construct 34.5 kV bus to connect the PV array to Liddie 230 kV Substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Interconnection ("Liddie") Substation is on site. No Gen-Tie Required.
2. No additional upgrades are expected to be necessary at this time.

III.E.25 Transmission Facilities for the Crist Unit 8 Combustion Turbine Project in Escambia County

The work required to connect Crist Unit 8, which consists of four simple cycle combustion turbines (CT) in late 2021, to the Gulf system in Escambia County is projected to be:

I. Substation:

1. Construct a 230 kV switchyard (Conecuh) for the four (4) approximately 235 MW CTs on Crist Plant property. Switchyard will have five (5) bays with breaker-and-a-half configuration.
2. Install four (4) main step-up transformers (4 - 315 MVA), one for each CT.
3. Install thirteen (13) - 230 kV independent-pole breakers in the Conecuh switchyard.
4. Replace all Crist 230 kV breakers with independent-pole breakers.
5. Replace 230/115kV autotransformer transformer with a 500 MVA unit at Bellview substation.
6. Add relays and other protective equipment.

II. Transmission:

1. Loop existing Crist-Alligator Swamp #2-230kV and Crist-Bellview 230kV lines into new Conecuh switchyard.
2. Relocate line terminal for Crist-Barry 230kV line into Conecuh substation.
3. Upgrade Brentwood-Crist 230kV to 1930 Amps (768 MVA, ~7.6 miles).
4. Upgrade Conecuh-Crist #1 and #2-230kV lines to 2000 Amps (797 MVA, ~0.2 miles).
5. Upgrade Crist-Scenic Hills #1-115kV to 1800 Amps (359 MVA, ~2.9 miles).
6. Upgrade Eastgate-Scenic Hills 115kV to 1005 Amps (200 MVA, ~4.8 miles).
7. Upgrade Bellview-Conecuh 230kV to 1930 Amps (768 MVA, 8.9 miles).

III.F. Renewable Resources and Storage Technology

Overview:

Even though solar energy-based resource options were generally not economically competitive on FPL's and Gulf's system until the 2016 time frame, both companies have been actively involved in renewable energy resource research and development since the mid-1970s. These activities have been numerous and varied as described below.

FPL's and Gulf's Renewable Energy Efforts Through 2019:

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. Since 1976, FPL has been an industry leader in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. FPL's and Gulf's renewable energy efforts through 2019 are briefly discussed in five categories of solar/renewable activities. Plans for new renewable energy facilities from 2020 through 2029 are then discussed in a separate section.

1) Early Research & Development Efforts:

In the late 1970s, FPL assisted the Florida Solar Energy Center (FSEC) in demonstrating the first residential PV system east of the Mississippi River. This PV installation at FSEC's Brevard County location was in operation for more than 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. In 1984, FPL installed a second PV system at its Flagami substation in Miami. This 10-kilowatt (kW) system operated for a number of years before it was removed to make room for substation expansion. In addition, FPL maintained a thin-film PV test facility at the FPL Martin Plant Site for a number of years to test new thin-film PV technologies.

Gulf has evaluated the potential for wind as a renewable energy resource in Northwest Florida through meteorological research along the coastal area. Gulf also participated in joint efforts with Southern Company research on various PV technology evaluations.

2) Demand Side & Customer Efforts:

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (because it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created to broadly disseminate information about passive solar building design techniques that are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, the program received a U.S. Department of Energy award for innovation and also led to a revision of the Florida Model Energy Building Code which was the incorporation of one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

FPL has continued to analyze and promote PV utilization. These efforts have included PV research, such as the 1991 research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. FPL's PV efforts also included educational efforts, such as FPL's Next Generation Solar Station Program. This initiative delivered teacher training and curriculum that was tied to the Sunshine Teacher Standards in Florida. The program provided teacher grants to promote and fund projects in the classrooms.

Gulf offered customers the opportunity to contribute to the development of solar PV beginning with the Solar for Schools program in the 1995 DSM Plan. This voluntary program ultimately developed multiple PV installations in schools across Northwest Florida and was used primarily for educational purposes. In 1999, Gulf offered customers an additional opportunity through an optional rate rider. The PV Rate Rider program was intended to give customers an opportunity to contribute towards the construction of a solar PV facility along with other customers across the Southern Company territory.

In 2008, Gulf received FPSC approval to offer an experimental solar water heating program. This program was intended to help customers overcome the high initial cost of adopting the solar thermal water heating technology. The program spanned three years and was absorbed into a larger portfolio of renewable program offerings in Gulf's 2010 DSM Plan.

In 2009, as part of its DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a certain capped amount annually to facilitate demand-side solar water heater and PV applications. The annual spending caps for these applications over the five-year period was approximately $15.5 million per year for FPL and approximately $576,000 per year for Gulf. In response to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of three PV-based programs and three solar water heating-based programs, plus a Renewable Research and Demonstration project. Gulf received similar approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of two PV-based programs and two solar water heating-based programs. Analyses of the results by both FPL and Gulf from these pilot programs since their inception consistently showed that none of these pilot programs was cost-effective for customers using any of the three cost-effectiveness screening tests used by the State of Florida. As a result, consistent with the FPSC's December 2014 DSM Goals Order No. PSC-14-0696-FOF-EU, these pilot programs expired on December 31, 2015.

Gulf conducted market research in 2015 indicating customer interest in a renewable energy alternative to rooftop PV. After further research into innovative offerings across the industry, Gulf developed a subscription-based program model commonly known as community solar. Gulf received FPSC approval in 2016 for a Community Solar program intended to facilitate construction of a 1 MW facility in Northwest Florida once adequate subscriptions were secured. However, customer interest to-date has not been adequate to justify construction of the project.

In addition, FPL and Gulf assist customers interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2019, approximately 17,000 customer systems (predominantly residential) have been interconnected with FPL and approximately 2,200 customer systems (predominately residential) have been interconnected with Gulf. These values represent approximately 0.3% of FPL's total number of customers, and approximately 0.5% of Gulf's total number of customers, respectively.

3) **<u>Supply Side Efforts – Power Purchases:</u>**

FPL has facilitated a number of renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.) through power purchase agreements (PPAs). FPL purchases firm capacity and energy, and/or as-available energy, from these types of facilities. For example, FPL has a contract to receive firm capacity from the Solid Waste Authority of Palm Beach (SWA) through April 2034.

Gulf currently has three PPAs with solar facilities totaling approximately 120 MW. In addition, Gulf has two PPAs totaling approximately 81 MW based, at least in part, on receiving wind-produced firm amounts of hourly energy from out-of-state sources. Tables I.A.3.1, I.A.3.2, I.A.3.3, I.B.3.1, I.B.3.2, and I.B.3.3 in Chapter I provide information regarding both firm and non-firm capacity PPAs from renewable energy facilities in the two areas.

4) <u>Supply Side Efforts – Utility Owned Facilities:</u>

At the time this Site Plan is filed, FPL owns 24 universal solar generating facilities that are in commercial operation, and Gulf owns one universal solar generating facility (Blue Indigo) that is scheduled to go into commercial operation at about the time this 2020 Site Plan is to be filed (April 1, 2020). All but one of these facilities are PV facilities and together they represent approximately 1,675 MW of generation for FPL and 74.5 MW of generation for Gulf Power. The other facility is a 75 MW solar thermal facility. Each of these solar facilities is listed below in Table III.F.1.

Table III.F.1: List of FPL- & Gulf-Owned Solar Facilities Through April 2020

	Solar Energy Center	Project	County	Nameplate MW	Type	COD
	FPL Area					
1	Desoto		Desoto	25	Tracking	Oct-09
2	Space Coast		Brevard	10	Fixed	Apr-10
3	Martin		Martin	75	Solar Thermal	Dec-10
4	Manatee		Manatee	74.5	Fixed	Dec-16
5	Citrus		DeSoto	74.5	Fixed	Dec-16
6	Babcock		Charlotte	74.5	Fixed	Dec-16
7	Horizon	SoBRA	Alachua / Putnam	74.5	Fixed	Jan-18
8	Coral Farms	SoBRA	Putnam	74.5	Fixed	Jan-18
9	Wildflower	SoBRA	DeSoto	74.5	Fixed	Jan-18
10	Indian River	SoBRA	Indian River	74.5	Fixed	Jan-18
11	Blue Cypress	SoBRA	Indian River	74.5	Fixed	Mar-18
12	Barefoot Bay	SoBRA	Brevard	74.5	Fixed	Mar-18
13	Hammock	SoBRA	Hammock	74.5	Fixed	Mar-18
14	Loggerhead	SoBRA	St. Lucie	74.5	Fixed	Mar-18
15	Miami-Dade	SoBRA	Miami-Dade	74.5	Fixed	Jan-19
16	Interstate	SoBRA	St. Lucie	74.5	Fixed	Jan-19
17	Sunshine Gateway	SoBRA	Columbia	74.5	Fixed	Jan-19
18	Pioneer Trail	SoBRA	Volusia	74.5	Fixed	Jan-19
19	Sweetbay	ST	Martin	74.5	Fixed	Jan-20
20	Northern Preserve	ST	Baker	74.5	Fixed	Jan-20
21	Cattle Ranch	ST	Desoto	74.5	Tracking	Jan-20
22	Twin Lakes	ST	Putnam	74.5	Tracking	Jan-20
23	Blue Heron	ST	Hendry	74.5	Fixed	Jan-20
24	Babcock Preserve	ST	Charlotte	74.5	Fixed	Jan-20
	Gulf Power Area					
25	Blue Indigo		Jackson	74.5	Fixed	Apr-20
	Totals					
	FPL Area Total Nameplate MW =			1,675		
	Gulf Power Area Total Nameplate MW =			74.5		
	Total Nameplate MW =			1,749		

5) **Ongoing Research & Development Efforts:**

FPL has a "Living Lab" across several of its office locations and select customer sites to demonstrate FPL's renewable energy commitment to employees and visitors. FPL currently has approximately 308 kW of PV as part of the Living Lab, including a 150 kW floating solar installation in Miami-Dade County. Through various Living Lab projects, FPL is able to evaluate multiple solar and storage technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses for FPL's customers. FPL plans to continue to expand the Living Lab as new technologies come to market, including a plan to add 500 kW of linear generators in 2020.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives, including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

In regard to PV's impact on the FPL system, FPL began in 2014 to develop a methodology to determine what firm capacity value at FPL's Summer and Winter peak hours would be appropriate to apply to existing, and potential PV facilities. The potential capacity contribution of PV facilities is dependent upon a number of factors including (but not necessarily limited to): site location, technology, design, and the total amount of solar that is operating on FPL's system. (Note that the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating.)

Based on the results of its analyses using that methodology, firm capacity values are assigned to each new solar facility. These firm capacity values are described in terms of the percentage of the facility's nameplate (AC) rating that can be counted on as firm capacity at the Summer and Winter peak load hours. For example, two of FPL's earliest PV facilities, DeSoto and Space Coast, have been assigned firm capacity values of approximately 46% for DeSoto and 32% for Space Coast at FPL's Summer peak hour (that typically occurs in the 4 p.m. to 5 p.m. hour), but contribute no firm capacity during FPL's Winter peak hour (that typically occurs in the 7 a.m. to 8 a.m. hour). Similarly, each new solar facility is assigned a specific firm capacity value based on the factors described above.

Gulf partnered with EPRI in 2016 as a host site for the SHINES (Sustainable and Holistic Integration of Energy Storage and Solar PV) project. This ongoing project evaluates the potential for transformer-level battery storage to work in conjunction with rooftop solar to manage energy flow on the distribution system. Advanced forecasting technology interacts with the solar and battery control systems to optimize customer loads and charging/discharging of the battery storage to minimize grid disruption. Gulf also conducted research on residential Tesla Powerwall battery systems to evaluate both the potential to shift solar contribution to peak hours and to dispatch storage as a demand-response resource.

Renewable Energy, Battery Storage, and Electric Vehicle Projections for 2020 through 2029:

This section addresses efforts regarding renewable energy in both universal (utility-scale) solar and customer-focused (distributed) solar. In addition, efforts regarding battery storage are also addressed. These efforts and plans are summarized below.

1) Universal Solar:

In 2009, FPL constructed 110 MW of solar energy facilities including two PV facilities totaling 35 MW and one 75 MW solar thermal facility. From 2009 through 2017, the costs of solar equipment, especially PV equipment, declined significantly and universal (i.e., utility-scale) PV facilities at a number of sites became increasingly competitive economically with more conventional generation options. As a result, FPL added three new PV facilities of approximately 74.5 MW each near the end of 2016.

In the first quarter of 2018, eight additional PV facilities of 74.5 MW each, or 596 MW in total, also went into commercial operation. These eight PV facilities were added under the Solar Base Rate Adjustment (SoBRA) provision of the Commission's order approving the settlement agreement for FPL's last base rate case in 2016 (Order No. PSC-16-0560-AS-EI) and comprised the first two tranches of four facilities each. In 2019, four more 74.5 MW PV facilities, or approximately 298 MW, were added as SoBRA facilities. An additional four 74.5 MW PV facilities, or approximately 298 MW, are in the final phase of construction and will be placed into commercial operation in the 2nd Quarter of 2020. This will complete the addition of solar under the current Solar Base Rate Adjustment (SoBRA) mechanism that resulted from FPL's 2016 base rate settlement agreement.

In regard to Gulf's area, one new 74.5 MW utility-owned PV facility, Blue Indigo, will be placed into commercial operation in April of 2020. The decision to add this PV facility was made based on resource planning work performed in 2019.

In this 2020 Site Plan, the resource plan shows a significant amount of solar being added throughout the 10-year projection period (2020 through 2029) of this Site Plan. A total of approximately 10,000 MW of solar is projected by the end of the year 2029. This total value consists of approximately 9,925 MW of PV and 75 MW of solar thermal. Ongoing resource planning work will continue to analyze the projected system economics of solar and all other resource options. Information regarding the Preferred and Potential Sites for the projected solar additions, particularly in the near-term, is presented in Chapter IV.

2) Customer-Focused PV Pilot Programs:

FPL began implementation of two customer-focused PV pilot programs in 2015. The first is a voluntary, community-based, solar partnership pilot to install new solar-powered generating facilities. The program is at least partially funded by contributions from customers who volunteer to participate in the pilot and will not rely on subsidies from non-participating customers. The second program will implement approximately 5 MW of DG PV. The objective of this second program is to collect grid integration data for distributed generation (DG) PV and develop operational best practices for addressing potential problems that may be identified. A brief description of these pilot programs follows.

a) Voluntary, Community-Based Solar Partnership Pilot Program:

The Voluntary Solar Pilot Program, named FPL SolarNow, provides FPL customers with an additional and flexible opportunity to support development of solar power in Florida. The FPSC approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. The pilot program's tariff became effective in January 2015. The pilot was recently approved for a third extension of an additional year by the FPSC in Order No. PSC-2019-0544-TRF-EI on December 20, 2019 and the pilot program is now scheduled to end at the close of 2020.

This pilot program provides all customers the opportunity to support bringing solar projects into local communities by funding the construction of solar facilities in local public areas, such as parks, zoos, schools, and museums. Customers can participate in the program through voluntary contributions of $9/month. As of the end of 2019, there were 48,897 participants enrolled in the Voluntary Solar Pilot Program. This program has installed 68 projects located in 64 different locations within the FPL service territory. These projects represent approximately 2,420 kW-DC of PV generation.

b) FPL SolarTogether, Shared Solar Program:

In March of 2019, FPL filed for FPSC approval of a community shared solar program. The program is named FPL SolarTogether. This voluntary program offers FPL customers the option to purchase capacity/energy from cost-effective, large-scale solar generation facilities. The proposed program will not require customers who participate to be bound to a long-term contract or subject to administrative fees or termination penalties. Under this program, participants' monthly electric bills would show both a subscription charge and a direct credit on their electric bills associated with the amount of solar-generated capacity purchased. This shared solar program will leverage the economies of scale of universal solar to deliver long-term savings to both program participants and non-participants.

In March 2020, the FPSC approved the SolarTogether program (Order PSC-2020-0084-S-EI). The first phase of the program is projected to add approximately 1,490 MW of new solar facilities[14].

c) **C&I Solar Partnership Pilot Program:**

This pilot program is conducted in partnership with interested commercial and industrial (C&I) customers over an approximate 5-year period that is scheduled to conclude in 2020. Limited investments will be made in PV facilities located at customer sites on selected distribution circuits within FPL's service territory.

The primary objective is to examine the effect of high localized PV penetration on FPL's distribution system and to determine how best to address any problems that may be identified. FPL has installed approximately 3.5 MW of PV facilities on circuits that experience specific loading conditions to better study feeder loading impacts. In addition, FPL is now evaluating the integration of solar into urban areas to test its impact on the distribution system on feeders that are heavily loaded as well as investigate the capabilities of "bifacial solar panel" technology, which, unlike traditional panels, is able to produce energy on both sides

Battery Storage Efforts:

Battery storage technology has continued to advance, and the costs of storage are projected to continue to decline. As a result, battery storage, particularly when charged solely by utility-scale solar facilities, has become an economically competitive firm capacity option for FPL's system. The resource plan presented in this 2020 Site Plan shows an increased amount of battery storage compared to what was presented in the 2019 Site Plan. As previously discussed, a 409 MW battery storage facility will be added in late 2021 at the existing Manatee plant site to partially offset the loss of capacity that will occur with the retirement of existing Manatee Units 1 & 2. Additional battery storage capacity is projected to be added by late 2021 with 30 MW of battery storage added at both the existing Sunshine Gateway Solar Energy Center and at the Echo River Solar Energy Center currently in

[14] In the SolarTogether community solar program, participating customers share in the costs and benefits of a dedicated FPL SolarTogether PV facility and are entitled, upon their request, to have the environmental attributes associated with their participation retired by FPL on their behalf.

construction. An additional total of approximately 700 MW of battery storage is also included in the resource plan in the years 2028 and 2029 in Gulf's area.

In addition, FPL is analyzing the potential of battery storage technology to benefit FPL's customers in other ways. These analyses have been, and are currently, being carried out through implementation of two pilot projects designed to evaluate different potential applications for batteries on FPL's system.

The objectives of the two pilot projects are to identify the most promising applications for batteries on FPL's system and to gain experience with battery installation and operation. This information will position FPL to expeditiously take advantage of battery storage for the benefit of FPL's and Gulf's customers as the economics of the technology continue to improve. For the purpose of discussing these two pilot projects, they will be referred to as the "small scale" and "large scale" storage pilot projects.

1) **Small Scale Storage Pilot Projects:**

In 2016 and early 2017, FPL installed approximately 4 MW of battery storage systems, spread across six sites, with the general objective of demonstrating the operational capabilities of batteries and learning how to integrate them into FPL's system. These small storage projects were designed with a distinct set of high-priority battery storage grid applications in mind. These applications include: peak shaving, frequency response, and backup power. In addition, these initial projects were designed to provide FPL with an opportunity to determine how to best integrate storage into FPL's operational software systems and how best to dispatch and/or control the storage systems.

To this end, FPL installed: (i) a 1.5 MW battery in Miami-Dade County primarily for peak shaving and frequency response, (ii) another 1.5 MW battery in Monroe County for backup power and voltage support, (iii) a relocatable 0.75 MW uninterruptible power supply (UPS) battery at the Tennis Center at Crandon Park in Key Biscayne for mitigation of momentary disruptions, and (iv) several smaller kilowatt-scale systems at other locations to study distributed storage reliability applications. All of these projects have been in service for more than 2 years and have yielded valuable information regarding the applications listed above.

2) **Large Scale (50 MW) Storage Pilot Project:**

The small scale energy storage pilot projects described above are complemented by up to 50 MW of additional battery projects that will be deployed. These pilot projects were authorized under the Settlement Agreement in FPL's 2016 base rate case. The 50 MW of batteries that will be deployed in this larger pilot project will expand the number of storage applications and configurations that FPL will be able to test, as well as making the scale of deployment more meaningful, given the large size of FPL's system.

The first two storage projects under this pilot involve pairing battery storage with existing universal PV facilities, and these projects went into service in the 1st Quarter of 2018. One of the projects is a 4 MW battery sited at FPL's Citrus Solar Energy Center, which captures clipped (curtailed) solar energy from the solar panels during high solar insolation hours, then releases this energy in other hours. The second of these two projects is a 10 MW battery at FPL's Babcock Ranch Solar Energy Center. This project is designed to shift PV output from non-peak times to peak times and also to provide "smoothing" of solar output and regulation services. These two projects are designed to enhance the operations of existing solar facilities that were installed in 2016 as outlined in FPL's base rate case Settlement Agreement. The data and lessons gathered from these two projects will result in more optimized design configurations for solar-paired battery projects as well as improved operational parameters for economic dispatch.

The third project, placed in-service in the 4th Quarter of 2019, is a 10 MW battery in Wynwood, a dense urban area that is close to downtown Miami. The project is designed to examine the use of batteries to support the distribution system with a focus on addressing grid, system, and customer challenges.

Three additional pilot projects are under development and expected to go in-service in 2020. One project entails deploying a 3 MW battery alongside an existing solar PV system to create a microgrid. The microgrid will be used for local resiliency and to provide additional grid services, including mitigation of disruptions potentially caused by solar in the distribution system. Another project currently under development will deploy up to 1 MW of Electric-Vehicle-to-Grid (EV2G) batteries using electric school buses that will be able to discharge electricity to the grid when needed. This project will explore the potential for utilizing electric vehicles as grid resources on FPL's system for the first time ever. Yet another project will site an 11.5 MW battery at the future Dania Beach Clean Energy Center Unit 7 to provide FPL an opportunity to test using battery storage for black start capability of large generating units.

Together, all of these projects will utilize approximately 39 MW of the 50 MW allowed under the Settlement Agreement. In regard to the remaining 11 MW of allowed storage capacity, FPL is continuing to evaluate which types of battery storage configurations and applications are projected to be the most meaningful to examine at this time. Potential project ideas are evaluated on an ongoing basis, considering current trends in the battery storage market, as well as the needs of FPL's system and the potential for projects of a given type to create future customer savings and value.

In addition to the two storage pilot projects described above (Small Scale and Large Scale 50 MW), FPL is now testing battery storage in the residential setting. This test involves up to 20 residential sites in the Palm Beach County area. The test addresses both potential benefits of having a 5-to-8 kW storage system for home backup power and the ability of FPL to remotely control the storage systems to provide services to the electric grid.

These battery storage pilot projects, plus other planned battery storage efforts projected to be in-service by late 2021/beginning of 2022, are presented in Table III.F.2 below. The table also presents the firm capacity values for Summer and Winter that FPL is currently assigning to these facilities. In total, FPL is currently projecting approximately 480 MW of cumulative firm capacity value from battery storage by 2022 and this firm capacity is accounted for in FPL's resource planning work.

Table III.F.2: List of FPL Battery Storage Facilities

In-Service Date	Location / Projects	Status	Nameplate MW	Firm Summer capacity MW	Firm Winter capacity MW
2016-2017	2016 Pilots	Operation	4	0	0
2018	Citrus Solar Energy Center	Operation	4	4	4
2018	Babcock Solar Energy Center	Operation	10	10	10
2019	Wynwood	Operation*	10	0	0
2020	Dania Beach Energy Center	Development	11.5	0	0
2020	Micro grid	Development	3	0	0
2020	EV2G	Development	0.4	0	0
2021	Manatee	Development	409	409	409
2022	Sunshine Gateway	Development	30	30	30
2022	Echo River	Development	30	23	30
	Total		**512**	**476**	**483**

* The Wynwood battery has 2 interconnection points. The first was energized in Dec. 2019; the second will be energized in Apr. 2020.

Electric Vehicle Efforts:

Florida continues to rank in the top four in the nation for electric vehicle (EV) adoption, and more Floridians are buying electric vehicles every year. FPL began implementation of the new FPL EVolution pilot program in 2019 to support the growth of EVs with the goal to install more than 1,000 charging ports, thus increasing the availability of public charging stations for EVs in Florida by 50%. This pilot program will be conducted in partnership with interested host customers over an approximate 3-year period. Limited investments will be made in EV charging infrastructure. Installations will encompass different EV charging technologies and market segments, including workplace, destination, public fast charging, and residential. These places will include rest stops, public parks, shopping malls, and large businesses that employ thousands of Florida residents. As of December 31, 2019, FPL has installed 50 ports at 7 locations.

In regard to EVs, the primary objective of the integrated utility is to examine EV use, adoption, potential new rate structures, power quality, and customer experience ahead of mass adoption to ensure future electric vehicle investments enhance service for electric customers who select EVs.

III.G Fuel Mix and Fuel Price Forecasts

1. Fuel Mix: FPL and Gulf

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fueled generation. In the early 1980s, FPL began to purchase “coal-by-wire.” In 1987, coal was first added to the fuel mix through FPL’s partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers’ energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4, which began serving FPL’s customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas, which FPL uses to produce electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of abundant, U.S.-produced natural gas. FPL placed into commercial operation two new gas-fueled CC units at the West County Energy Center (WCEC) site in 2009. FPL added a third new CC unit to the WCEC site in 2011. In addition, FPL has completed the modernization of its Cape Canaveral, Riviera Beach, and Port Everglades plant sites. These new CC units have dramatically improved the efficiency of FPL's generation system in general and, more specifically, the efficiency with which natural gas is utilized. In March of 2018, the FPSC authorized a modernization of FPL's Lauderdale site in which two existing steam-type generating units were retired in late 2018, and a new, much more fuel-efficient CC unit, DBEC Unit 7, will be added at the site by mid-2022.

The uprates at Plant Smith's Unit 3 in Gulf's area will increase the efficiency of the current unit, and alternatives that allow more output from existing units across the FPL and Gulf systems will continue to be evaluated. The addition of 4 CT's at Plant Crist in 2021, capable of burning natural gas or ULSD oil, will provide additional fuel diversity and reliability.
FPL has also taken measures over the last few years to reduce the use of coal as a fuel. FPL shuttered Cedar Bay in 2016, St. Johns River Power Park in 2018 and plans to retire the Indiantown Co-Gen coal-fueled unit in late 2020. Gulf's conversion of the Crist plant to natural gas in 2020 demonstrates a continued commitment to eliminate coal from the generation portfolio.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 500 MW of additional nuclear capacity have been added to the FPL system. As mentioned previously, FPL has obtained the Combined Operating Licenses from the NRC for two new nuclear units, Turkey Point Units 6 & 7. FPL has now paused in this process to decide when to pursue approval from the FPSC to proceed to construction. In addition, on January 30, 2018, FPL applied to the Nuclear Regulatory Commission (NRC) for Subsequent License Renewal (SLR) for FPL's Turkey Point Units 3 & 4. The current license terms for these two existing nuclear units extend into the years 2032 and 2033, respectively. The SLR request has now been approved by the NRC which extends the operating licenses for Turkey Point Units 3 & 4 by 20 years to 2052 and 2053, respectively.

In regard to utilizing renewable energy, by April 2020, FPL will have an approximate 75 MW solar thermal steam generating facility at the existing Martin site and a total of approximately 1,675 MW PV generating capability comprised of 74.5 MW solar facilities at 23 other sites. In addition, Gulf has one 74.5 MW PV facility. A significant amount of additional solar is projected in the current resource plan as discussed throughout this Site Plan. However, as previously discussed in this chapter, the contribution to fuel diversity of this additional PV capability will be lower on a MWh basis than the large MW additions of PV might suggest.

Ongoing resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance long-term fuel diversity. These fuel-diverse alternatives may include: the purchase of power from renewable energy facilities, additional solar energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent and Marcellus regions, preserving the ability to utilize fuel oil at existing units, and increased utilization of nuclear energy. (As previously discussed, new, advanced technology coal-fueled generating units are not currently considered as viable options in Florida in the 10-year reporting period of this document.) The evaluation of the feasibility and cost-effectiveness of these and other possible fuel diversity alternatives will be part of on-going resource planning efforts.

Current use of various fuels to supply energy to customers, plus a projection of this “fuel mix” through 2029 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 that appear later in this chapter. As noted on Schedules 6.1 and 6.2, the fuel mix projections for the Gulf system for the years 2020 and 2021 were provided by the Southern Company which will continue to operate the Gulf generating units until the FPL and Gulf systems are integrated into a single operating system.

2. Fossil Fuel Cost Forecasts

FPL’s Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used to evaluate alternatives for meeting future resource needs. FPL’s forecasts are generally consistent with other published contemporary forecasts. A January 2020 fuel cost forecast was used in the analyses which developed the resource plan presented in this 2020 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscore the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, Low, Medium, and High price forecasts for fossil fuels were developed in anticipation of the 2020 resource planning work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For the current + 2 years (2020-2022), the methodology used the January 2020 forward curve for New York Harbor 0.7% sulfur heavy oil, WTI Crude Oil, Ultra-Low Sulfur Diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2023 and 2024), FPL used a 50/50 blend of the January 2020 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2025 through 2040 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2040, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. Forecasted coal prices were based upon the following approach:

a. JD Energy provides regular (once every 1-2 months) short-term price forecasts (currently through 2021 issued in December 2019) for Powder River Basin (PRB) minemouth/FOB coal.

b. JD Energy also provides a long-term price forecast through 2065 of the delivered price of coal to Scherer. The most recent forecast was issued in September 2019.

c. The short term delivered coal price forecast for Plant Scherer is updated with PRB minemouth/FOB coal price updates from JD Energy while keeping the long-term prices the same as the September 2019 long-term forecast.

d. Beyond 2065, prices are escalated at JD Energy's annual price escalation from 2064 to 2065.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. FPL's approach has been to then adjust the Medium fuel cost forecast upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

Gulf Power's Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used to evaluate alternatives for meeting future resource needs. Gulf Power's forecasts are generally consistent with other published contemporary forecasts. A January 2020 fuel cost forecast was used in analyses, the results of which led to the resource plan presented in this 2020 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscore the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, Low, Medium, and High price forecasts for fossil fuels were developed in anticipation of the 2020 resource planning work.

Gulf's Medium price forecast methodology for natural gas is consistent with FPL's methodology for natural gas and light oil. For natural gas and light oil commodity prices, Gulf's Medium price forecast applies the following methodology:

a. For the current + 2 years (2020-2022), the methodology used the January 2020 forward curve for Henry Hub natural gas and Ultra-Low Sulfur Diesel (ULSD) fuel oil commodity prices;
b. For the next two years (2023 and 2024), a 50/50 blend of the January 2020 forward curve, and the most current projections at the time from The PIRA Energy Group, were used;

c. For the 2025 through 2040 period, the annual projections from The PIRA Energy Group were used; and,

d. For the period beyond 2040, the real rate of escalation from the Energy Information Administration (EIA) was used. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

Gulf's Medium price forecast methodology for coal is also consistent with FPL's methodology for coal prices at Plant Scherer. Forecasted coal prices were based upon the following approach:

a. JD Energy provides regular (once every 1-2 months) short-term price forecasts (currently through 2021 issued in December 2019) for Powder River Basin (PRB), Uinta Basin, Illinois River Basin (ILB) and Colombian minemouth/FOB coal.

b. JD Energy also provides a long-term price forecast through 2065 of the delivered price of coal to Crist, Smith, and Scherer. The most recent forecast was issued in September 2019.

c. The short-term delivered coal price forecast for Plant Scherer is updated with PRB minemouth/FOB coal price updates from JD Energy while keeping the long-term prices the same as the September 2019 long-term forecast.

d. Currently coal price forecasts for plants Crist and Daniels are kept the same as the September 2019 long-term coal forecast provided by JD Energy.

e. Beyond 2065, all plant prices are escalated at JD Energy's annual price escalation from 2064 to 2065.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

3. Natural Gas Storage

FPL currently has under contract 4.0 billion cubic feet (Bcf) of firm natural gas storage capacity at the Bay Gas storage facility in Alabama. The contract is set to expire March 31, 2021, but will automatically renew for up to four more successive one-year terms unless otherwise terminated by either party on or before December 31 of 2020. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. To diversify FPL's natural gas storage portfolio, FPL entered into a storage contract with SG Resources Mississippi, L.L.C. (Southern Pines Storage) for 1 Bcf of storage capacity. The current contract with Southern Pines Storage is set to expire March 31, 2022. This storage facility is located in Mississippi and is connected to numerous pipelines including FGT, Southeast Supply Header, and Transco. Gulf currently holds total storage capacity of 2.45 Bcf across three facilities: Bay Gas (1.1 Bcf), Leaf River (0.85 Bcf), and Petal (0.50 Bcf). This storage capacity is utilized for Plant Smith, Plant Crist, and Gulf's SENA (Shell) PPA.

Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As the integrated utility system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide the ability to manage its supply and demand on a daily basis. The gas storage portfolio is continually evaluated and subscription for additional gas storage capacity is possible if needed to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas:

Significant reliance upon natural gas to produce electricity for FPL's customers is projected to continue over the long-term due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral, Riviera Beach, Port Everglades, and Okeechobee, plus the additional CC capacity at the Dania Beach site that will come in-service in 2022, will reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. In addition, as discussed above, FPL currently plans to add significantly more solar PV facilities that utilize no fossil fuel.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies: FGT and Gulfstream. In mid-2017, a third new pipeline system, consisting of the Sabal Trail and Florida Southeast Connection pipelines, went into operation. This new pipeline system is now providing fuel for FPL's Riviera and Martin plants. The new pipeline system also provides the primary fuel for the recently added Okeechobee CC unit. The new pipeline system will also allow needed support for gas-fueled FPL generation facilities in several counties.

Southern Company Services (SCS) is currently managing the fuel supply for the Gulf power plants. Gulf is working to transition some of these fuel management activities by the end of 2021, but nothing has been transitioned to-date. Gulf is currently working with SCS to determine the appropriate fuel plans for the increased gas requirements at Plants Crist and Smith.

5. Nuclear Fuel Cost Forecast

This section discusses the various steps needed to fabricate nuclear fuel for delivery to nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U_3O_8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U_3O_8 is chemically converted into UF_6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.0% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF_6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF_6 is changed to a UO_2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market because the majority of the Japanese nuclear reactors are still not operating. As a result, current demand has remained declined and several of the production facilities have either closed or announced delays. Factors of importance are:

- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- Although only two new nuclear units are scheduled to start production in the U.S. during the next 2 to 3 years, other countries, more specifically China, have

announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020 (an extension of these restrictions is currently under review). New and current uranium production facilities are decreasing capacity due to continued low prices and demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increases in prices, but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production is currently forecasted to be insufficient to meet a higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond the current level if more firm commitments are made. FPL expects long-term price stability for conversion services to support world demand.

(3) Enrichment: Since the Fukushima events in March 2011, the near-term price of enrichment services has declined. However, plans for construction of several new facilities that were expected to come on-line after 2011 have been delayed and/or cancelled. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will likely result in the price of enrichment services remaining stable for the next few years, then starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for

U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. There is adequate projected supply, including planned and prospective mine expansions, to meet FPL demands, including operation of the Turkey Point nuclear units through the recently approved second life extension through the early 2050s.

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Schedule 5: Actual
Fuel Requirements

			Actual 1/			
	Fuel Requirements	Units	2018	2019	2018	2019
			FPL		Gulf	
(1)	Nuclear	Trillion BTU	309	303	0	0
(2)	Coal	1,000 TON	1,691	1,684	2,935	2,687
(3)	Residual (FO6) - Total	1,000 BBL	440	187	0	0
(4)	Steam	1,000 BBL	440	187	0	0
(5)	Distillate (FO2) - Total	1,000 BBL	187	203	30	17
(6)	Steam	1,000 BBL	4	1	27	17
(7)	CC	1,000 BBL	94	191	0	0
(8)	CT	1,000 BBL	89	11	3	0
(9)	Natural Gas - Total	1,000 MCF	660,569	665,984	59,283	28,616
(10)	Steam	1,000 MCF	38,572	29,028	1,255	1,124
(11)	CC	1,000 MCF	616,949	630,185	56,948	27,492
(12)	CT	1,000 MCF	5,048	6,771	1,080	0
(13)	Other 2/	1,000 MCF	0	0	250	0

1/ Source: A Schedules.
2/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 5: Forecasted
Fuel Requirements

						Forecasted							
Fuel Requirements	**Units**	**2020**	**2021**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
		FPL		**Gulf**		**Integrated FPL and Gulf**							
(1) Nuclear	Trillion BTU	298	298	0	0	305	298	301	306	301	300	307	301
(2) Coal	1,000 TON	1,003	1,132	514	189	77	146	87	152	178	187	206	152
(3) Residual (FO6) - Total	1,000 BBL	0	13	0	0	0	0	0	0	0	0	0	0
(4) Steam	1,000 BBL	0	13	0	0	0	0	0	0	0	0	0	0
(5) Distillate (FO2) - Total	1,000 BBL	9	5	3	5	39	10	21	24	9	22	19	16
(6) Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	5	2	0	0	33	3	11	19	2	9	9	5
(8) CT	1,000 BBL	4	3	3	5	7	8	10	6	7	13	11	11
(9) Natural Gas - Total	1,000 MCF	594,809	575,238	28,846	33,608	617,672	631,009	637,355	625,116	615,165	604,104	591,178	583,767
(10) Steam	1,000 MCF	2,126	1,522	5,088	10,121	4,055	8,097	6,768	6,613	5,930	5,183	3,491	1,906
(11) CC	1,000 MCF	588,978	570,110	23,738	23,460	610,518	619,975	628,258	614,965	607,363	596,260	585,060	580,366
(12) CT	1,000 MCF	3,705	3,606	20	27	3,098	2,937	2,329	3,538	1,871	2,660	2,627	1,494
(13) Other [2/]	1,000 MCF	0	0	246	245	245	245	245	240	245	245	245	256

1/ Source: A Schedules.
2/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1 Actual
Energy Sources

			Actual [1/]			
	Energy Sources	**Units**	**2018**	**2019**	**2018**	**2019**
			FPL		**Gulf**	
(1)	Annual Energy Interchange [2/]	GWH	0	0	(3,095)	(3,556)
(2)	Nuclear	GWH	28,176	27,791	0	0
(3)	Coal	GWH	2,586	2,488	5,526	4,125
(4)	Residual(FO6) -Total	GWH	248	223.5	0	0
(5)	Steam	GWH	248	224	0	0
(6)	Distillate(FO2) -Total	GWH	129	223.5	1	0
(7)	Steam	GWH	2	14	0	0
(8)	CC	GWH	78	204	0	0
(9)	CT	GWH	49	5	1	0
(10)	Natural Gas -Total	GWH	91,214	93,373	8,150	8,808
(11)	Steam	GWH	3,133	2,442	29	62
(12)	CC	GWH	87,625	90,302	3,934	3,913
(13)	CC PPAs - Gas	GWH	0	0	4,114	4,833
(14)	CT	GWH	456	630	73	0
(15)	Solar [3/]	GWH	1,887	2,396	227	232
(16)	PV	GWH	1,836	2,368	0	0
(17)	Solar Together [4/]	GWH	0	0	0	0
(18)	Solar Thermal	GWH	51	28	0	0
(19)	Solar PPAs	GWH	0	0	227	232
(20)	Wind PPAs	GWH	0	0	1,031	1,031
(21)	Other [5/]	GWH	(1,793)	(1,328)	218	1,101
	Net Energy For Load [6/]	GWH	122,447	125,168	12,057	11,742

1/ Sources: Actuals for FPL and Gulf: A Schedules and Actual Data for Next Generation Solar Centers Report. Forecast for Gulf 2020 and 2021: Projections from Southern Company
2/ Represents interchange between FPL/Gulf and other utilities. For Gulf, this number represents the net energy exchange with Southern Co.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL’s SolarTogether (ST) program. At the request of any ST participant, environmental attributes in the form of renewable energy certificates for that participant’s allocation of the total energy produced will be retired on the participant’s behalf.
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2020 - 2029 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2 Actual
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/ 2018 FPL	Actual 1/ 2019 FPL	Actual 1/ 2018 Gulf	Actual 1/ 2019 Gulf
(1)	Annual Energy Interchange 2/	%	0.0	0.0	(25.7)	(30.3)
(2)	Nuclear	%	23.0	22.2	0.0	0.0
(3)	Coal	%	2.1	2.0	45.8	35.1
(4)	Residual (FO6) -Total	%	0.2	0.2	0.0	0.0
(5)	Steam	%	0.2	0.2	0.0	0.0
(6)	Distillate (FO2) -Total	%	0.1	0.2	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0
(8)	CC	%	0.1	0.2	0.0	0.0
(9)	CT	%	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	74.5	74.6	67.6	75.0
(11)	Steam	%	2.6	2.0	0.2	0.5
(12)	CC	%	71.6	72.1	32.6	33.3
(13)	CC PPAs - Gas	%	0.0	0.0	34.1	41.2
(14)	CT	%	0.4	0.5	0.6	0.0
(15)	Solar 3/	%	1.5	1.9	1.9	2.0
(16)	PV	%	1.5	1.9	0.0	0.0
(17)	Solar Together 4/	%	0.0	0.0	0.0	0.0
(18)	Solar Thermal	%	0.0	0.0	0.0	0.0
(19)	Solar PPAs	%	0.0	0.0	1.9	2.0
(20)	Wind PPAs	%	0.0	0.0	8.6	8.8
(21)	Other 5/	%	(1.5)	(1.1)	1.8	9.4
			100	100	100	100

1/ Sources: Actuals for FPL and Gulf: A Schedules and Actual Data for Next Generation Solar Centers Report. Forecast for Gulf 2020 and 2021: Projections from Southern Company
2/ Represents interchange between FPL/Gulf and other utilities. For Gulf, this number represents the net energy exchange with Southern Co.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. At the request of any ST participant, environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced will be retired on the participant's behalf.
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.

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Schedule 6.1 Forecasted Energy Sources

	Energy Sources	Units	2020	2021	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
			FPL		Gulf [1]		Forecasted Integrated FPL and Gulf							
(1)	Annual Energy Interchange [2]	GWH	0	0	(4,576)	(4,538)	0	0	0	0	0	0	0	0
(2)	Nuclear	GWH	28,162	28,395	0	0	28,978	28,319	28,556	29,037	28,598	28,519	29,110	28,590
(3)	Coal	GWH	1,404	1,582	2,793	1,906	110	207	127	224	265	279	312	232
(4)	Residual(FO6) -Total	GWH	0	9	0	0	0	0	0	0	0	0	0	0
(5)	Steam	GWH	0	9	0	0	0	0	0	0	0	0	0	0
(6)	Distillate(FO2) -Total	GWH	5	3	0	0	29	3	10	19	4	9	9	5
(7)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	4	2	0	0	26	2	8	15	1	7	7	4
(9)	CT	GWH	1	1	0	0	3	1	2	4	2	2	2	1
(10)	Natural Gas -Total	GWH	88,099	85,382	11,876	12,660	94,603	95,049	95,067	93,254	91,945	90,245	88,268	87,157
(11)	Steam	GWH	208	148	1,365	2,317	365	738	608	604	536	475	320	177
(12)	CC	GWH	87,532	84,891	4,789	4,744	91,268	93,096	94,237	92,314	91,233	89,519	87,696	86,837
(13)	CC PPAs - Gas	GWH	0	0	5,655	5,532	2,671	933	0	0	0	0	0	0
(14)	CT	GWH	360	343	67	67	300	281	222	337	176	250	251	144
(15)	Solar [3]	GWH	4,366	6,679	416	413	8,587	9,483	10,402	12,075	14,805	17,528	20,294	22,947
(16)	PV	GWH	3,200	3,423	191	190	4,831	5,738	6,659	8,352	11,093	13,826	16,594	19,268
(17)	Solar Together [4]	GWH	1,041	3,130	0	0	3,407	3,397	3,396	3,377	3,367	3,357	3,355	3,336
(18)	Solar Thermal	GWH	126	125	0	0	125	125	126	125	125	125	126	125
(19)	Solar PPAs	GWH	0	0	224	223	223	222	222	221	220	219	219	218
(20)	Wind PPAs	GWH	0	0	1,033	1,031	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031
(21)	Other [5]	GWH	1,036	1,084	172	171	1,460	1,508	1,565	1,901	1,894	1,864	1,848	1,789
	Net Energy For Load [6]	GWH	123,073	123,134	11,715	11,643	134,800	135,600	136,761	137,540	138,541	139,474	140,874	141,751

1/ Sources: Actuals for FPL and Gulf: A Schedules and Actual Data for Next Generation Solar Centers Report. Forecast for Gulf 2020 and 2021: Projections from Southern Company
2/ Represents interchange between FPL/Gulf and other utilities. For Gulf, this number represents the net energy exchange with Southern Co.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program.
At the request of any ST participant, environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced will be retired on the participant's behalf.
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2020 - 2029 are also shown in Col. (19) on Schedule 2.3.

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Schedule 6.2 Forecasted
Energy Sources % by Fuel Type

	Energy Source	Units	FPL 2020	FPL 2021	Gulf [1/] 2020	Gulf [1/] 2021	Forecasted (Integrated FPL and Gulf) 2022	2023	2024	2025	2026	2027	2028	2029
(1)	Annual Energy Interchange [2/]	%	0.0	0.0	(39.1)	(39.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2)	Nuclear	%	22.9	23.1	0.0	0.0	21.5	20.9	20.9	21.1	20.6	20.4	20.7	20.2
(3)	Coal	%	1.1	1.3	23.8	16.4	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2
(4)	Residual (FO6) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	Distillate (FO2) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	71.6	69.3	101.7	108.8	70.2	70.1	69.5	67.8	66.4	64.7	62.7	61.5
(11)	Steam	%	0.2	0.1	12.0	20.0	0.3	0.5	0.4	0.4	0.4	0.3	0.2	0.1
(12)	CC	%	71.1	68.9	40.9	40.7	67.7	68.7	68.9	67.1	65.9	64.2	62.3	61.3
(13)	CC PPAs - Gas	%	0.0	0.0	48.3	47.5	2.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0
(14)	CT	%	0.3	0.3	0.6	0.6	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.1
(15)	Solar 3/	%	3.5	5.4	3.6	3.5	6.4	7.0	7.6	8.8	10.7	12.6	14.4	16.2
(16)	PV	%	2.6	2.8	1.6	1.6	3.6	4.2	4.9	6.1	8.0	9.9	11.8	13.6
(17)	Solar Together [4/]	%	0.8	2.5	0.0	0.0	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4
(18)	Solar Thermal	%	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(19)	Solar PPAs	%	0.0	0.0	1.9	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(20)	Wind PPAs	%	0.0	0.0	8.8	8.9	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7
(21)	Other [5/]	%	0.8	0.9	1.5	1.5	1.1	1.1	1.1	1.4	1.4	1.3	1.3	1.3
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Sources: Actuals for FPL and Gulf: A Schedules and Actual Data for Next Generation Solar Centers Report. Forecast for Gulf 2020 and 2021: Projections from Southern Company
2/ Represents interchange between FPL/Gulf and other utilities. For Gulf, this number represents the net energy exchange with Southern Co.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program.
At the request of any ST participant, environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced will be retired on the participant's behalf.
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
FPL															
2020	27,145	110	0	434	27,689	24,624	1,786	22,838	4,851	21.2	0	4,851	21.2	3,065	12.4
2021	27,722	110	0	4	27,836	24,720	1,833	22,887	4,948	21.6	0	4,948	21.6	3,116	12.6
Gulf															
2020	2,389	1,039	0	0	3,429	2,464	6	2,458	970	39.5	0	970	39.5	965	39.1
2021	2,389	1,039	0	0	3,428	2,496	14	2,482	947	38.1	0	947	38.1	932	37.3
Integrated FPL and Gulf															
2022	30,763	1,149	0	4	31,915	27,220	1,903	25,317	6,599	26.1	0	6,599	26.1	4,695	17.2
2023	31,164	264	0	4	31,431	27,564	1,962	25,602	5,829	22.8	0	5,829	22.8	3,867	14.0
2024	31,061	264	0	4	31,328	27,953	2,026	25,927	5,401	20.8	0	5,401	20.8	3,375	12.1
2025	31,386	263	0	4	31,653	28,349	2,071	26,278	5,375	20.5	0	5,375	20.5	3,304	11.7
2026	31,892	263	0	4	32,159	28,775	2,107	26,668	5,490	20.6	0	5,490	20.6	3,384	11.8
2027	32,230	263	0	0	32,493	29,143	2,142	27,001	5,492	20.3	0	5,492	20.3	3,350	11.5
2028	32,639	263	0	0	32,902	29,592	2,177	27,415	5,486	20.0	0	5,486	20.0	3,310	11.2
2029	33,322	262	0	0	33,585	30,195	2,212	27,983	5,602	20.0	0	5,602	20.0	3,390	11.2

Col. (2) represents peak capacity additions and changes projected to be in-service by June 1st of each year. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col.(7) reflects the 2019 peak load forecasts without incremental energy efficiency after 9/2019 or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental energy efficiency and load management, from 9/2019-on, intended for use with the 2019 load forecasts.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
								FPL							
2020	26,908	110	0	404	27,422	19,959	1,360	18,599	8,822	47.4	0	8,822	47.4	7,463	37.4
2021	26,989	110	0	4	27,103	20,250	1,387	18,863	8,239	43.7	0	8,239	43.7	6,853	33.8
								Gulf							
2020	2,345	994	0	0	3,339	2,256	0	2,256	1,083	48.0	0	1,083	48.0	1,083	48.0
2021	2,345	994	0	0	3,339	2,293	6	2,287	1,052	46.0	0	1,052	46.0	1,046	45.6
								Integrated FPL and Gulf							
2022	28,479	1,104	0	4	29,587	22,369	1,430	20,939	8,647	41.3	0	8,647	41.3	7,218	32.3
2023	29,766	1,104	0	4	30,874	22,617	1,468	21,149	9,725	46.0	0	9,725	46.0	8,257	36.5
2024	29,559	219	0	4	29,782	22,861	1,508	21,353	8,429	39.5	0	8,429	39.5	6,921	30.3
2025	29,741	219	0	4	29,964	23,103	1,555	21,548	8,415	39.1	0	8,415	39.1	6,861	29.7
2026	29,983	219	0	4	30,206	23,388	1,585	21,803	8,403	38.5	0	8,403	38.5	6,818	29.1
2027	29,908	219	0	0	30,127	23,608	1,616	21,992	8,135	37.0	0	8,135	37.0	6,519	27.6
2028	30,068	219	0	0	30,287	23,941	1,647	22,294	7,993	35.9	0	7,993	35.9	6,346	26.5
2029	30,568	219	0	0	30,787	24,293	1,677	22,616	8,171	36.1	0	8,171	36.1	6,494	26.7

Col. (2) represents firm capacity additions and changes projected to be in-service by January 1st of each year. These MW are generally considered to be available to meet Winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col.(7) reflects the 2019 peak load forecasts without incremental energy efficiency after 9/2019 or cumulative load management. The January 2020 load is an actual load value.
Col.(8) represents cumulative load management capability, plus incremental energy efficiency and load management, from 9/2019-on, intended for use with the 2019 load forecasts.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

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Schedule 8

Planned And Prospective Generating Facility Additions And Changes (1) : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
FPL Changes														
2020														
Northern Preserve Solar[3] (Solar facility in-service January of 2020)	1	Baker County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Twin Lakes Solar[3] (Solar facility in-service January of 2020)	1	Putnam County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Cattle Ranch Solar[3] (Solar facility in-service January of 2020)	1	Desoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Sweetbay Solar[3] (Solar facility in-service January of 2020)	1	Martin County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Babcock Preserve Solar[3] (Solar facility in-service January of 2020)	1	Charlotte County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Blue Heron Solar[3] (Solar facility in-service January of 2020)	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2020	Unknown	74,500	-	41	P
Hibiscus Solar[3]	1	Palm Beach County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2020	Unknown	74,500	-	41	P
Southfork Solar[3]	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2020	Unknown	74,500	-	41	P
Echo River Solar[3]	1	Suwannee County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2020	Unknown	74,500	-	41	P
Okeechobee Solar[3]	1	Okeechobee Manatee County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2020	Unknown	74,500	-	41	P
Sanford	4	Volusia County	CC	NG	No	PL	No	-	2nd Q 2020	Unknown	1,265,732	-	147	OP
											2020 Changes/Additions Total:	**0**	**560**	
2021														
Sanford	4	Volusia County	CC	NG	No	PL	No	-	2nd Q 2020	Unknown	1,265,732	41	-	OP
West County	3	Palm Beach County	CC	NG	FO2	PL	TK	-	3rd Q 2020	Unknown	1,366,800	20	21	OP
Turkey Point	4	Miami Dade County	ST	Nuc	No	TK	No	-	4th Q 2020	Unknown	877,200	20	20	OP
Lakeside Solar[3]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Trailside Solar[3]	1	St. Johns County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Union Springs Solar[3]	1	Union County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Magnolia Springs Solar[3]	1	Clay County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Egret Solar[3]	1	Baker County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Nassau Solar[3]	1	Nassau County	PV	Solar	Solar	N/A	N/A	-	4th Q 2020	Unknown	74,500	-	39	P
Pelican Solar[3]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Palm Bay Solar[3]	1	Brevard County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Discovery Solar[3]	1	Brevard County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Orange Blossom Solar[3]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Sabal Palm Solar[3]	1	Palm Beach County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Fort Drum Solar[3]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Rodeo Solar[3]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Willow Solar[3]	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2021	Unknown	74,500	-	39	P
Solar Degradation[4]	NA	NA	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(3)	OT
											2021 Changes/Additions Total:	**81**	**577**	
Integrated FPL and Gulf: FPL Changes														
2022														
Manatee Retirement	1	Manatee County	ST	NG	FO6	PL	WA	-	Oct-76	4th Q 2021	863,300	(819)	(809)	P
Manatee Retirement	2	Manatee County	ST	NG	FO6	PL	WA	-	Dec-77	4th Q 2021	863,300	(819)	(809)	P
Scherer Retirement	4	Monroe, GA	ST	SUB	No	RR	No	-	Jul-89	4th Q 2021	680,368	(635)	(634)	P
Manatee Energy Storage	1	Manatee County	BS	N/A	N/A	N/A	N/A	-	4th Q 2021	Unknown		409	409	P
Sunshine Gateway Energy Storage	1	Columbia County	BS	N/A	N/A	N/A	N/A	-	4th Q 2021	Unknown		30	30	P
Echo River Energy Storage	1	Suwannee County	BS	N/A	N/A	N/A	N/A	-	4th Q 2021	Unknown		30	30	P
Fort Myers Upgrade	2	Lee County	CC	NG	No	PL	No	-	2nd Q 2022	Unknown	1,836,798	-	40	OP
Dania Beach Clean Energy Center	7	Broward County	CC	NG	FO2	PL	WA	-	2nd Q 2022	Unknown		-	1,163	P
Solar Degradation[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(5)	OT
											2022 Changes/Additions Total:	**(1,804)**	**(585)**	

(1) Schedule 8 shows only planned and prospective changes to FPL and Gulf generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, I.A.3.2, I.B.3.1 and I.B.3.2.
(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by August. All MW additions/changes occurring after August each year will be acounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.
(3) Solar MW values reflect firm capacity only values, not nameplate ratings.
(4) An annual 0.3% degradation for PV output is assumed for both FPL and Gulf Solar. Total degradation shown is for both FPL and Gulf.

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Planned And Prospective Generating Facility Additions And Changes (1) : FPL

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability (2) Winter MW	(14) Firm Net Capability (2) Summer MW	(15) Status
ADDITIONS/ CHANGES														
Integrated FPL and Gulf Continued: FPL Changes														
2023														
Dania Beach Clean Energy Center	7	Broward County	CC	NG	FO2	PL	WA		2nd Q 2022	Unknown	-	1,176	-	P
Martin Upgrade	8	Martin County	CC	NG	FO2	PL	TK	-	4th Q 2022	Unknown	-	28	40	OP
Manatee Upgrade	3	Manatee County	CC	NG	No	PL	No	-	2nd Q 2023	Unknown	1,301,382	28	79	OP
Fort Myers Upgrade	2	Lee County	CC	NG	No	PL	No	-	3rd Q 2023	Unknown	1,836,798	55	79	OP
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(6)	OT
										2023 Changes/Additions Total:		**1,287**	**192**	
2024														
Martin Upgrade	8	Martin County	CC	NG	FO2	PL	TK	-	4th Q 2022	Unknown	-	28	-	OP
Manatee Upgrade	3	Manatee County	CC	NG	No	PL	No	-	2nd Q 2023	Unknown	1,301,382	83	-	OP
Fort Myers Upgrade	2	Lee County	CC	NG	No	PL	No	-	3rd Q 2023	Unknown	1,836,798	110	-	OP
Turkey Point Upgrade	5	Miami Dade County	CC	NG	FO2	PL	TK	-	1st Q 2024	Unknown	1,301,382	-	79	OP
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	1st Q 2024	Unknown	1,886,150	-	58	OP
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(6)	OT
										2024 Changes/Additions Total:		**221**	**131**	
2025														
Turkey Point Upgrade	5	Miami Dade County	CC	NG	FO2	PL	TK	-	1st Q 2024	Unknown	1,301,382	110	-	OP
Solar PV(3)		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2025	Unknown		-	264	P
Sanford Upgrade	4	Volusia County	CC	NG	No	PL	No	-	2nd Q 2025	Unknown	1,265,732	34	78	OP
Sanford Upgrade	5	Volusia County	CC	NG	No	PL	No	-	2nd Q 2025	Unknown	1,265,732	34	78	OP
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	Apr-19	Unknown	1,886,150	79	-	OP
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(7)	OT
										2025 Changes/Additions Total:		**257**	**413**	
2026														
Martin Upgrade	8	Martin County	CC	NG	FO2	PL	TK	-	4th Q 2025	Unknown	-	55	40	OP
Sanford Upgrade	4	Volusia County	CC	NG	No	PL	No	-	4th Q 2025	Unknown	1,265,732	101	26	OP
Sanford Upgrade	5	Volusia County	CC	NG	No	PL	No	-	4th Q 2025	Unknown	1,265,732	101	26	OP
Solar PV(3)		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2026	Unknown		-	422	P
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(8)	OT
										2026 Changes/Additions Total:		**257**	**506**	
2027														
Solar PV(3)		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2027	Unknown		-	422	P
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(9)	OT
										2027 Changes/Additions Total:		**0**	**413**	
2028														
Solar PV(3)		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2028	Unknown		-	252	P
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(11)	OT
										2028 Changes/Additions Total:		**0**	**241**	
2029														
Solar PV(3)		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2029	Unknown		-	194	P
Solar Degradation(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(11)	OT
										2029 Changes/Additions Total:		**0**	**183**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to expisting purchases. Those changes are reflected on Tables ES-1, I.A.3.1, I.A.3.2, I.B.3.1 and I.B.3.2.
(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.
(3) Solar values reflect firm capacity only values, not nameplate ratings.
(4) An annual 0.3% degradation for PV output is assumed for both FPL and Gulf Solar. Total degradation shown is for both FPL and Gulf.

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Planned And Prospective Generating Facility Additions And Changes (1) : Gulf

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
Gulf Changes														
2020														
Blue Indigo Solar[3] (Solar facility in-service April 1st of 2020)	1	Jackson County	PV	Solar	Solar	N/A	N/A	-	Apr-20	Unknown	74,500	-	41	P
											2020 Changes/Additions Total:	**0**	**41**	
2021														
											2021 Changes/Additions Total:	**0**	**0**	
Integrated FPL and Gulf: Gulf Changes														
2022														
4X0 Crist CTs	8	Escambia County	CT	NG	FO2	PL	N/A	-	4th Q 2021	Unknown		949	938	P
Blue Springs Solar [3/]	1	Jackson County	PV	Solar	Solar	N/A	N/A	-	4th Q 2021	Unknown		-	37	P
Chautauqua Solar [3/]	1	Walton County	PV	Solar	Solar	N/A	N/A	-	4th Q 2021	Unknown		-	37	P
Solar PV[3]		Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2022	Unknown		-	224	P
											2022 Changes/Additions Total:	**949**	**1,237**	
2023														
Solar PV[3]		Unknown	PV	Solar	Solar	N/A	N/A		1st Q 2023	Unknown	-	-	209	P
											2023 Changes/Additions Total:	**0**	**209**	
2024														
Lansing Smith Upgrade	3	Bay County	CC	NG	No	PL	No	-	Nov-23	Unknown	656,100	74	59	OP
Daniel Retirement	1	Jackson County, MS	FS	C	No	RR	No	-	Sep-77	1st Q 2024	274,125	(251)	(251)	P
Daniel Retirement	2	Jackson County, MS	FS	C	No	RR	No	-	Jun-81	1st Q 2024	274,125	(251)	(251)	P
Solar PV[3]		Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2024	Unknown	-	-	209	P
											2024 Changes/Additions Total:	**(428)**	**(234)**	
2025														
Crist Retirement	4	Escambia County	FS	C	NG	WA	PL	-	Jul-59	4th Q 2024	93,750	(75)	(75)	P
Pea Ridge Retirement	1	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	4,750	-	(4)	P
Pea Ridge Retirement	2	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	4,750	-	(4)	P
Pea Ridge Retirement	3	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	4,750	-	(4)	P
											2025 Changes/Additions Total:	**(75)**	**(87)**	
2026														
Pea Ridge Retirement	1	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	Apr-25	4,750	(5)	-	P
Pea Ridge Retirement	2	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	Apr-25	4,750	(5)	-	P
Pea Ridge Retirement	3	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	Apr-25	4,750	(5)	-	P
											2026 Changes/Additions Total:	**(15)**	**0**	
2027														
Crist Retirement	5	Escambia County	FS	C	NG	WA	PL	-	Jul-59	4th Q 2026	93,750	(75)	(75)	P
											2027 Changes/Additions Total:	**(75)**	**(75)**	
2028														
Lansing Smith Retirement	A	Bay County	CT	LO	No	TK	No		May-71	4th Q 2027	41,850	(40)	(32)	OP
Energy Storage		Unknown	BS	N/A	N/A	N/A	N/A		1st Q 2028	Unknown		200	200	P
											2028 Changes/Additions Total:	**160**	**168**	
2029														
Energy Storage		Unknown	BS	N/A	N/A	N/A	N/A		1st Q 2029	Unknown		500	500	P
											2029 Changes/Additions Total:	**500**	**500**	

(1) Schedule 8 shows only planned and prospective changes to FPL and Gulf generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, I.A.3.2, I.B.3.1 and I.B.3.2.

(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by August. All MW additions/changes occurring after August each year will be acounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total are due to rounding.

(3) Solar MW values reflect firm capacity only values, not nameplate ratings and 0.3% degradation is assumed annually for PV output. Degradation for Gulf is captured on FPL's schedule 8.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Hibiscus Solar Energy Center (Palm Beach County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	41	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	402	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.2%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,373	
	Direct Construction Cost (2020 $/kW):	1,341	
	AFUDC Amount (2020 $/kW):	32	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	6.27	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	0.98	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Okeechobee Solar Energy Center (Okeechobee County)
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	41	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**	471	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	27.1%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,339	
	Direct Construction Cost (2020 $/kW):	1,298	
	AFUDC Amount (2020 $/kW):	41	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	6.41	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	1.04	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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(1)	**Plant Name and Unit Number:**		Southfork Solar Energy Center (Manatee County)
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	41	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	548	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	31.1%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,407	
	Direct Construction Cost (2020 $/kW):	1,339	
	AFUDC Amount (2020 $/kW):	68	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	6.70	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	1.03	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Echo River Solar Energy Center (Suwannee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	41	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	802	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	30.4%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,394	
	Direct Construction Cost (2020$/kW):	1,330	
	AFUDC Amount (2020 $/kW):	63	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	7.06	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	1.03	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Lakeside Solar Energy Center (Okeechobee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	693	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.8%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,205	
	Direct Construction Cost (2020 $/kW):	1,169	
	AFUDC Amount (2020 $/kW):	36	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	6.57	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	1.06	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Trailside Solar Energy Center (St. Johns County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 39 MW (Approximately)
c. Winter Firm (AC) -

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2019
b. Commercial In-service date: 2020

(5) **Fuel**
a. Primary Fuel: Solar
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 846 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	26.8%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh

(13) **Projected Unit Financial Data ***

Book Life (Years):	30	years
Total Installed Cost (2020 $/kW):	1,245	
Direct Construction Cost (2020 $/kW):	1,207	
AFUDC Amount (2020 $/kW):	38	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2020 $)	7.10	(First Full Year Operation)
Variable O&M ($/MWH): (2020 $)	0.00	
K Factor:	1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Union Springs Solar Energy Center (Union County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 39 MW (Approximately)
c. Winter Firm (AC) -

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2019
b. Commercial In-service date: 2020

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 725 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	26.5%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
Base Operation 75F,100%		
Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
Peak Operation 75F,100%		

(13) **Projected Unit Financial Data ***

Book Life (Years):	30	years
Total Installed Cost (2020 $/kW):	1,242	
Direct Construction Cost (2020 $/kW):	1,205	
AFUDC Amount (2020 $/kW):	38	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2020 $)	7.10	(First Full Year Operation)
Variable O&M ($/MWH): (2020 $)	0.00	
K Factor:	1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Magnolia Springs Solar Energy Center (Clay County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	850	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		26.5% (First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):		Not applicable Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):		30 years
	Total Installed Cost (2020 $/kW):		1,197
	Direct Construction Cost (2020 $/kW):		1,160
	AFUDC Amount (2020 $/kW):		36
	Escalation ($/kW):		Accounted for in Direct Construction Cost
	Fixed O&M ($/kW-Yr.): (2020 $)		6.92 (First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)		0.00
	K Factor:		1.07

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Egret Solar Energy Center (Baker County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	676	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		26.4% (First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%		Not applicable Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%		Not applicable Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):		30 years
	Total Installed Cost (2020 $/kW):		1,151
	Direct Construction Cost (2020 $/kW):		1,114
	AFUDC Amount (2020 $/kW):		37
	Escalation ($/kW):		Accounted for in Direct Construction Cost
	Fixed O&M ($/kW-Yr.): (2020 $)		6.92 (First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)		0.00
	K Factor:		1.08

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Nassau Solar Energy Center (Nassau County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2019	
	b. Commercial In-service date:	2020	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	928	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.2%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2020 $/kW):	1,300	
	Direct Construction Cost (2020 $/kW):	1,261	
	AFUDC Amount (2020 $/kW):	38	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2020 $)	7.10	(First Full Year Operation)
	Variable O&M ($/MWH): (2020 $)	0.00	
	K Factor:	1.07	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Pelican Solar Energy Center (St. Lucie County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	565	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.7%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,265	
	Direct Construction Cost (2021 $/kW):	1,227	
	AFUDC Amount (2021 $/kW):	38	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	6.57	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.06	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

[1/] The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Palm Bay Solar Energy Center (Brevard County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	486	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.8%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,229	
	Direct Construction Cost (2021 $/kW):	1,191	
	AFUDC Amount (2021 $/kW):	38	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	6.74	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

[1/] The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Discovery Solar Energy Center (Brevard County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 39 MW (Approximately)
c. Winter Firm (AC) -

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2020
b. Commercial In-service date: 2021

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 491 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	24.3%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
Base Operation 75F,100%		
Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
Peak Operation 75F,100%		

(13) **Projected Unit Financial Data ***

Book Life (Years):	30	years
Total Installed Cost (2021 $/kW):	1,087	
Direct Construction Cost (2021 $/kW):	1,052	
AFUDC Amount (2021 $/kW):	35	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2021 $)	6.57	(First Full Year Operation)
Variable O&M ($/MWH): (2021 $)	0.00	
K Factor:	1.07	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

[1/] The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Orange Blossom Solar Energy Center (Indian River County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	607	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.7%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,217	
	Direct Construction Cost (2021 $/kW):	1,179	
	AFUDC Amount (2021 $/kW):	38	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	6.74	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sabal Palm Solar Energy Center (Palm Beach County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	39	MW (Approximately)
c. Winter Firm (AC)	-	

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date: 2020
b. Commercial In-service date: 2021

(5) **Fuel**

a. Primary Fuel: Solar
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 646 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	26.8%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh

(13) **Projected Unit Financial Data ***

Book Life (Years):	30	years
Total Installed Cost (2021 $/kW):	1,345	
Direct Construction Cost (2021 $/kW):	1,306	
AFUDC Amount (2021 $/kW):	40	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2021 $)	6.74	(First Full Year Operation)
Variable O&M ($/MWH): (2021 $)	0.00	
K Factor:	1.07	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Drum Solar Energy Center (Okeechobee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	930	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	23.8%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,137	
	Direct Construction Cost (2021 $/kW):	1,102	
	AFUDC Amount (2021 $/kW):	35	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	6.74	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Rodeo Solar Energy Center (DeSoto County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	1,193	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	27.6%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,113	
	Direct Construction Cost (2021 $/kW):	1,076	
	AFUDC Amount (2021 $/kW):	36	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	6.92	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Willow Solar Energy Center (Manatee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	39	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**[2/]		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	812	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.8%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,186	
	Direct Construction Cost (2021 $/kW):	1,149	
	AFUDC Amount (2021 $/kW):	37	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	7.10	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	1.10	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Blue Springs Solar Energy Center (Jackson County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	37	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	444	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.4%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR):	Not applicable	Btu/kWh
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):	Not applicable	Btu/kWh
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,071	
	Direct Construction Cost (2021 $/kW):	1,039	
	AFUDC Amount (2021 $/kW):	32	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	7.65	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	0.91	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

[1/] The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Chautauqua Solar Energy Center (Walton County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	37	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	688	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26.4%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2021 $/kW):	1,071	
	Direct Construction Cost (2021 $/kW):	1,039	
	AFUDC Amount (2021 $/kW):	32	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2021 $)	7.65	(First Full Year Operation)
	Variable O&M ($/MWH): (2021 $)	0.00	
	K Factor:	0.91	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Crist Unit 8 4x0 Combustion Turbine

(2) **Capacity**
a. Summer 938 MW
b. Winter 949 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2020
b. Commercial In-service date: 2021

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NOx Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection

(7) **Cooling Method:** Fin Fan / Evap Coolers

(8) **Total Site Area:** Existing Site

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.0%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96.0%	
Resulting Capacity Factor (%):	Approx. 3%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	9,944	
Average Net Incremental Heat Rate (ANIHR): Peak Firing and Wet Compression 75F,100%	8,869	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40	years
Total Installed Cost (2021 $/kW):	479	
Direct Construction Cost (2021 $/kW):	455	
AFUDC Amount (2021 $/kW):	23	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr. (2021 $)	8.00	
Variable O&M ($/MW (2021 $)	0.02	
K Factor:	1.13	

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Manatee Energy Storage Center

(2) **Capacity**
a. Summer 409 MW
b. Winter 409 MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2020
b. Commercial In-service date: 2021

(5) **Fuel**
a. Primary Fuel Not applicable
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** Existing Site 40 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):		Not applicable
Forced Outage Factor (FOF):		Not applicable
Equivalent Availability Factor (EAF):		Not applicable
Resulting Capacity Factor (%):		Not applicable
Average Net Operating Heat Rate (ANOHR):		Not applicable
Base Operation 75F,100%		
Average Net Incremental Heat Rate (ANIHR):		Not applicable
Peak Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):		10 years
Total Installed Cost (2021 $/kW):		TBD
Direct Construction Cost (2021 $/kW):		TBD
AFUDC Amount (2021 $/kW):		TBD
Escalation ($/kW):		TBD
Fixed O&M ($/kW-Yr.):	(2021 $)	TBD
Long Term Capital Replenishment ($/kW)	(2021 $)	TBD
Variable O&M ($/MWH):	(2021 $)	TBD
K Factor:		TBD

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement and annual capital replenishment

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Sunshine Gateway Energy Storage Center	
(2)	**Capacity**		
	a. Summer	30 MW	
	b. Winter	30 MW	
(3)	**Technology Type:** Battery		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2020	
	b. Commercial In-service date:	2021	
(5)	**Fuel**		
	a. Primary Fuel		Not applicable
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	Existing Site	30 Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		Not applicable
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		10 years
	Total Installed Cost (2021 $/kW):		TBD
	Direct Construction Cost (2021 $/kW):		TBD
	AFUDC Amount (2021 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.):	(2021 $)	TBD
	Long Term Capital Replenishment ($/kW)	(2021 $)	TBD
	Variable O&M ($/MWH):	(2021 $)	TBD
	K Factor:		TBD

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement and annual capital replenishment

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Echo River Energy Storage Center	
(2)	**Capacity**			
	a. Summer	30	MW	
	b. Winter	30	MW	
(3)	**Technology Type:** Battery			
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:		2020	
	b. Commercial In-service date:		2021	
(5)	**Fuel**			
	a. Primary Fuel			Not applicable
	b. Alternate Fuel			Not applicable
(6)	**Air Pollution and Control Strategy:**			Not applicable
(7)	**Cooling Method:**		Not applicable	
(8)	**Total Site Area:**		Existing Site	5 Acres
(9)	**Construction Status:**		P	(Planned Unit)
(10)	**Certification Status:**		---	
(11)	**Status with Federal Agencies:**		---	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):			Not applicable
	Forced Outage Factor (FOF):			Not applicable
	Equivalent Availability Factor (EAF):			Not applicable
	Resulting Capacity Factor (%):			Not applicable
	Average Net Operating Heat Rate (ANOHR):			Not applicable
	Base Operation 75F,100%			
	Average Net Incremental Heat Rate (ANIHR):			Not applicable
	Peak Operation 75F,100%			
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):			10 years
	Total Installed Cost (2021 $/kW):			TBD
	Direct Construction Cost (2021 $/kW):			TBD
	AFUDC Amount (2021 $/kW):			TBD
	Escalation ($/kW):			TBD
	Fixed O&M ($/kW-Yr.):		(2021 $)	TBD
	Long Term Capital Replenishment ($/kW)		(2021 $)	TBD
	Variable O&M ($/MWH):		(2021 $)	TBD
	K Factor:			TBD

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement and annual capital replenishment

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Dania Beach Clean Energy Center Unit 7

(2) **Capacity**
a. Summer 1,163 MW
b. Winter 1,176 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2020
b. Commercial In-service date: 2022

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NOx Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection

(7) **Cooling Method:** Once through cooling water

(8) **Total Site Area:** Existing Site 392 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%
Forced Outage Factor (FOF):	1%
Equivalent Availability Factor (EAF):	95.5%
Resulting Capacity Factor (%):	90.0% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	6,119 Btu/kWh on Gas
Average Net Incremental Heat Rate (ANIHR): Peak Firing and Wet Compression 75F,100%	7,592 Btu/kWh on Gas

(13) **Projected Unit Financial Data *,****

Book Life (Years):		40 years
Total Installed Cost (2022 $/kW):		764
Direct Construction Cost (2022 $/kW):		675
AFUDC Amount (2022 $/kW):		89
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2022 $)	19.73
Variable O&M ($/MWH):	(2022 $)	0.23
K Factor:		1.55

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	447	MW (in six 74.5 MW increments)
	b. Summer Firm (AC)[1/]	224	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing** [2/]		
	a. Field construction start-date:		2021
	b. Commercial In-service date:		2022
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2022 $/kW):		TBD
	Direct Construction Cost (2022 $/kW):		TBD
	AFUDC Amount (2022 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2022 $)		TBD
	Variable O&M ($/MWH): (2022 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	447	MW (in six 74.5 MW increments)
	b. Summer Firm (AC)[1/]	209	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2022
	b. Commercial In-service date:		2023
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%		Not applicable
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%		Not applicable
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2023 $/kW):		TBD
	Direct Construction Cost (2023 $/kW):		TBD
	AFUDC Amount (2023 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2023 $)		TBD
	Variable O&M ($/MWH) (2023 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	447	MW (in six 74.5 MW increments)
	b. Summer Firm (AC)[1/]	209	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2023
	b. Commercial In-service date:		2024
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applica Acres
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2024 $/kW):		TBD
	Direct Construction Cost (2024 $/kW):		TBD
	AFUDC Amount (2024 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2024 $)		TBD
	Variable O&M ($/MWH): (2024 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	745	MW (in ten 74.5 MW increments)
	b. Summer Firm (AC)[1/]	264	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2024
	b. Commercial In-service date:		2025
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2025 $/kW):		TBD
	Direct Construction Cost (2025 $/kW):		TBD
	AFUDC Amount (2025 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2025 $)		TBD
	Variable O&M ($/MWH): (2025 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited PV

(2) **Capacity**
a. Nameplate (AC) 1,192 MW (in sixteen 74.5 MW increments)
b. Summer Firm (AC)1/ 422 MW (Approximately)
c. Winter Firm (AC) -

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** Not applicable

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): TBD
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data**
Book Life (Years): 30 years
Total Installed Cost (2026 $/kW): TBD
Direct Construction Cost (2026 $/kW): TBD
AFUDC Amount (2026 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2026 $) TBD
Variable O&M ($/MWH): (2026 $) TBD
K Factor: TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	1,192	MW (in sixteen 74.5 MW increments)
	b. Summer Firm (AC)[1/]	422	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2026
	b. Commercial In-service date:		2027
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2027 $/kW):		TBD
	Direct Construction Cost (2027 $/kW):		TBD
	AFUDC Amount (2027 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2027 $)		TBD
	Variable O&M ($/MWH) (2027 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	1,192	MW (in sixteen 74.5 MW increments)
	b. Summer Firm (AC)[1/]	251	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2027
	b. Commercial In-service date:		2028
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2028 $/kW):		TBD
	Direct Construction Cost (2028 $/kW):		TBD
	AFUDC Amount (2028 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2028 $)		TBD
	Variable O&M ($/MWH): (2028 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited Energy Storage	
(2)	**Capacity**			
	a. Summer	200	MW	
	b. Winter	200	MW	
(3)	**Technology Type:** Battery			
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:		2027	
	b. Commercial In-service date:		2028	
(5)	**Fuel**			
	a. Primary Fuel			Not applicable
	b. Alternate Fuel			Not applicable
(6)	**Air Pollution and Control Strategy:**			Not applicable
(7)	**Cooling Method:**		Not applicable	
(8)	**Total Site Area:**		Not applicable	
(9)	**Construction Status:**		P	(Planned Unit)
(10)	**Certification Status:**		---	
(11)	**Status with Federal Agencies:**		---	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):			Not applicable
	Forced Outage Factor (FOF):			Not applicable
	Equivalent Availability Factor (EAF):			Not applicable
	Resulting Capacity Factor (%):			Not applicable
	Average Net Operating Heat Rate (ANOHR):			Not applicable
	Base Operation 75F,100%			
	Average Net Incremental Heat Rate (ANIHR):			Not applicable
	Peak Operation 75F,100%			
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):			10 years
	Total Installed Cost (2028 $/kW):			TBD
	Direct Construction Cost (2028 $/kW):			TBD
	AFUDC Amount (2028 $/kW):			TBD
	Escalation ($/kW):			TBD
	Fixed O&M ($/kW-Yr.):		(2028 $)	TBD
	Long Term Capital Replenishment ($/kW)		(2028 $)	TBD
	Variable O&M ($/MWH):		(2028 $)	TBD
	K Factor:			TBD

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement and annual capital replenishment

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Unsited PV
(2)	**Capacity**		
	a. Nameplate (AC)	1,192	MW (in sixteen 74.5 MW increments)
	b. Summer Firm (AC)[1/]	194	MW (Approximately)
	c. Winter Firm (AC)	-	
(3)	**Technology Type:** Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:		2028
	b. Commercial In-service date:		2029
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		Not applicable
(6)	**Air Pollution and Control Strategy:**		Not applicable
(7)	**Cooling Method:**		Not applicable
(8)	**Total Site Area:**		Not applicable
(9)	**Construction Status:**		P (Planned Unit)
(10)	**Certification Status:**		---
(11)	**Status with Federal Agencies:**		---
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		Not applicable
	Forced Outage Factor (FOF):		Not applicable
	Equivalent Availability Factor (EAF):		Not applicable
	Resulting Capacity Factor (%):		TBD
	Average Net Operating Heat Rate (ANOHR):		Not applicable
	Base Operation 75F,100%		
	Average Net Incremental Heat Rate (ANIHR):		Not applicable
	Peak Operation 75F,100%		
(13)	**Projected Unit Financial Data**		
	Book Life (Years):		30 years
	Total Installed Cost (2029 $/kW):		TBD
	Direct Construction Cost (2029 $/kW):		TBD
	AFUDC Amount (2029 $/kW):		TBD
	Escalation ($/kW):		TBD
	Fixed O&M ($/kW-Yr.): (2029 $)		TBD
	Variable O&M ($/MWH): (2029 $)		TBD
	K Factor:		TBD

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased. FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Energy Storage

(2) **Capacity**
a. Summer 500 MW
b. Winter 500 MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel: Not applicable
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** Not applicable

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Resulting Capacity Factor (%):	Not applicable
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data *,****

Book Life (Years):		10 years
Total Installed Cost (2029 $/kW):		TBD
Direct Construction Cost (2029 $/kW):		TBD
AFUDC Amount (2029 $/kW):		TBD
Escalation ($/kW):		TBD
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD
Long Term Capital Replenishment ($/kW)	(2029 $)	TBD
Variable O&M ($/MWH):	(2029 $)	TBD
K Factor:		TBD

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement and annual capital replenishment

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Hibiscus Solar Energy Center (Palm Beach County)

The Hibiscus Solar Energy Center will require bifurcating the FPL Ranch-Corbett 230 kV line approximately 1-mile west of FPL's Westlake substation to loop into the new Minto Substation.

(1) Point of Origin and Termination:	Westlake-Corbett 230 kV line section to Minto Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.07 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Minto Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Okeechobee Solar Energy Center (Okeechobee County)

The Okeechobee Solar Energy Center will connect to the new Okeechobee Next Generation Clean Energy Center project and does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Southfork Solar Energy Center (Manatee County)

The Southfork Solar Energy Center will require bifurcating the existing FPL Manatee-Keentown 230 kV transmission line looping the new Duette substation.

(1) Point of Origin and Termination:	Manatee-Keentown 230 kV line to Duette Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.15 mile
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Duette Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Echo River Solar Energy Center (Suwannee County)

The Echo River Solar Energy Center will require bifurcating the existing Suwannee (Duke Energy Florida, DEF) – Columbia (FPL) 115 kV tie line between FPL's Wellborn-Live Oak section, looping the new Hogan Substation.

(1) Point of Origin and Termination:	Wellborn-Live Oak 115 kV line section to Hogan Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.05 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Hogan Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lakeside Solar Energy Center (Okeechobee County)

The Lakeside Solar Energy Center will require bifurcating the existing FPL Martin-Sherman 230 kV transmission line and looping the new Nubbin Substation adjacent to the existing line.

(1) Point of Origin and Termination:	Martin-Sherman 230 kV line to Nubbin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	300 feet
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Nubbin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Trailside Solar Energy Center (St. Johns County)

The Trailside Solar Energy Center will require bifurcating the existing FPL Putnam-St. Johns 115 kV transmission line between the Elkton-St. Johns section and extending two parallel sections approximately 1 mile to loop the new Moccasin Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Elkton-St. Johns 115 kV line to Moccasin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	1 mile (double-circuit)
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Moccasin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Union Springs Solar Energy Center (Union County)

The Union Springs Solar Energy Center will require bifurcating the existing FPL Raven-Bradford 115 kV transmission line between the Bradford-Lake Butler section and extending two parallel sections approximately 0.1 mile to loop the new Plum Substation.

(1) Point of Origin and Termination:	Bradford-Lake Butler 115 kV line section to Plum Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.1 mile
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Plum Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Magnolia Springs Solar Energy Center (Clay County)

The Magnolia Springs Solar Energy Center will require bifurcating the existing Seminole Plant-Springbank 230 kV transmission line between the Titanium-Green Cove Springs section and extending two parallel sections approximately 0.1 mile to loop a new Leno substation.

(1) Point of Origin and Termination:	Titanium-Green Cove Springs 230 kV line section to Leno substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.1 mile
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Leno Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Egret Solar Energy Center (Baker County)

The Egret Solar Energy Center will require bifurcating the existing FPL Duval-Raven 230 kV transmission line and extending two parallel sections approximately 2 miles to loop the new Claude Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Duval-Raven 230 kV line to Claude Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	2 miles (double-circuit)
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Claude Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Nassau Solar Energy Center (Nassau County)

The Nassau Solar Energy Center will require bifurcating the existing FPL Duval-Yulee 230 kV transmission line between the Duval-West Nassau (GTC) section and extending two parallel sections approximately 1 mile to loop the new Crawford Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Duval-West Nassau (GTC) 230 kV line to Crawford Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	1 mile (double-circuit)
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2019 End date: 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Crawford Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Pelican Solar Energy Center (St. Lucie County)

The Pelican Solar Energy Center will require extending a 230 kV transmission line from Eldora Substation to the new Morrow Substation to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Eldora 230 kV Substation to Morrow Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	1.25 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: 2021
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Morrow Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Palm Bay Solar Energy Center (Brevard County)

The Palm Bay Solar Energy Center will require bifurcating the existing FPL Midway-Malabar 230 kV transmission line between the Glendale-Hield section and extending two parallel sections approximately 2.5 miles to loop the new Hayward Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Glendale-Hield 230 kV line to Hayward Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	2.5 miles (double-circuit)
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: 2021
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Hayward Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Discovery Solar Energy Center (Brevard County)

The Discovery Solar Energy Center will require bifurcating the existing FPL C5-Barna 115 kV transmission line and looping the new Rocket Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	C5-Barna kV line to Rocket Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	300 feet
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: 2021
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Rocket Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Orange Blossom Solar Energy Center (Indian River County)

The Orange Blossom Solar Energy Center will connect to the existing FPL Eldora-Heritage 230 kV transmission line via a line switch to connect the new Finca Substation and the solar PV inverter array.

(1) Point of Origin and Termination:	None
(2) Number of Lines:	0
(3) Right-of-way	N/A
(4) Line Length:	0
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: 2021
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Finca Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sabal Palm Solar Energy Center (Palm Beach County)

The Sabal Palm Solar Energy Center will require extending a transmission line from the Minto Substation approximately 1.5 miles to connect the new Costa Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Minto Substation to Costa Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	1.5 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: 2021
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Costa Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Drum Solar Energy Center (Okeechobee County)

The Fort Drum Solar Energy Center will connect to the new Okeechobee Next Generation Clean Energy Center project and does not require any new transmission lines.

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Rodeo Solar Energy Center (DeSoto County)

The Rodeo Solar Energy Center will connect to the Gleam substation at the new Cattle Ranch Solar Energy Center and does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Willow Solar Energy Center (Manatee County)

The Willow Solar Energy Center will require bifurcating the existing FPL Keentown-Sunshine 230 kV transmission line to connect a new Coachwhip substation and the solar PV inverter array.

(1) Point of Origin and Termination:	Keentown-Sunshine 230 kV line to new Coachwhip Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2020 End date: Late 2020
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Coachwhip Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Battery Storage in Manatee County

The 409 MW Battery Storage project in Manatee County does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sunshine Gateway Battery Energy Storage addition in Columbia County

The Sunshine Gateway Battery Energy Storage addition project in Columbia County does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Echo River Battery Energy Storage addition in Suwannee County

The Echo River Battery Energy Storage addition project in Suwannee County does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Dania Beach Clean Energy Center Unit 7

Dania Beach Clean Energy Center Unit 7 does not require any new transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Blue Springs Solar Energy Center (Jackson County)

The Blue Springs Solar Energy Center will require bifurcating the existing Gulf Cypress-Chipola section of the Gulf Marianna-West Grandridge 115 kV transmission line to connect a new Americus substation and the solar PV inverter array.

(1) Point of Origin and Termination:	Gulf Marianna-West Grandridge 115 kV line to new Americus Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	2 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2021 End date: 2022
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Americus Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Chautauqua Solar Energy Center (Walton County)

The Chautauqua Solar Energy Center will require bifurcating the existing Gulf Shoal River-Samson 230 kV transmission to connect a new Liddie substation and the solar PV inverter array.

(1) Point of Origin and Termination:	Gulf Shoal River-Samson 230 kV line to new Liddie Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	TBD
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2021 End date: 2022
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Liddie Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Crist Unit 8 Combustion Turbine Project (Escambia County)

The Crist Unit 8 Combustion Turbine Project will require bifurcating the existing Crist-Alligator Swamp #2-230kV and Crist-Bellview 230kV lines near Crist to connect into a new Conecuh substation switchyard, and relocating the existing line terminal at Crist for the Crist-Barry 230 kV line to Conecuh substation.

(1) Point of Origin and Termination:	Crist substation to new Conecuh substation
(2) Number of Lines:	3
(3) Right-of-way	FPL – Owned
(4) Line Length:	Approximately 0.25 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2021 End date: 2022
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Conecuh Substation
(9) Participation with Other Utilities:	None

Schedule 11.1: FPL

Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type
Actuals for the Year 2019

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh (2)**	**%**
(1)	Coal	634	2.3%	635	2.2%	2,488	2.0%
(2)	Nuclear	3,479	12.6%	3,570	12.5%	27,791	22.2%
(3)	Residual	0	0.0%	0	0.0%	224	0.2%
(4)	Distillate	108	0.4%	123	0.4%	224	0.2%
(5)	Natural Gas	21,731	78.9%	22,580	79.2%	93,373	74.6%
(6)	Solar (Firm & Non-Firm)	1,153	4.2%	1,153	4.0%	2,396	1.9%
(7)	***FPL Existing Units Total (1) :***	***27,105***	***98.4%***	***28,061***	***98.4%***	***126,496***	***101.1%***
(8)	Renewables (Purchases)- Firm	114.0	0.4%	114.0	0.4%	892	0.7%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	209	0.2%
(10)	***Renewable Total:***	114.0	0.4%	114.0	0.4%	1,101	0.88%
(11)	***Purchases Other / (Sales) :***	330.0	1.2%	330.0	1.2%	(2,429)	-1.9%
(12)	***Total :***	*27,548.8*	*100.0%*	*28,504.6*	*100.0%*	*125,168*	*100.0%*

Note:

(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the Total System Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2019.

Schedule 11.1: Gulf

Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type
Actuals for the Year 2019

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh (2)	%
(1)	Coal	1,641	67.6%	1,641	66.9%	4,125	35.1%
(2)	Nuclear	0	0.0%	0	0.0%	0	0.0%
(3)	Residual	0	0.0%	0	0.0%	0	0.0%
(4)	Distillate	32	1.3%	40	1.6%	0	0.0%
(5)	Natural Gas	672	27.7%	661	26.9%	3,975	33.9%
(6)	Landfill Gas	3	0.1%	3	0.1%	0	0.0%
(7)	Solar (Firm & Non-Firm)	0	0.0%	0	0.0%	0	0.0%
(8)	***Gulf Existing Units Total (1) :***	***2,348***	***96.7%***	***2,345***	***95.6%***	***8,101***	***69.0%***
(9)	Renewables (Purchases)- Firm	81.0	3.3%	109.0	4.5%	1,031	8.8%
(10)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	373	3.2%
(11)	***Renewable Total:***	81.0	3.3%	109.0	4.5%	1,404	11.95%
(12)	***Purchases Other / (Sales) :***	0.0	0.0%	0.0	0.0%	2,237	19.1%
(13)	***Total :***	*2,429.0*	*100.0%*	*2,454.0*	*100.0%*	*11,742*	*100.0%*

Note:
(1) Gulf Existing Units Total values on row (7), columns (2) and (4), match the Total System Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2019.

Schedule 11.2: FPL

Existing Non-Firm Self-Service Renewable Generation Facilities
Actuals for the Year 2019 [1/]

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh) 2/	Annual Energy Purchased from FPL (MWh) 3/	Annual Energy Sold to FPL - Total (MWh) 4/	Projected Annual Energy Used by Customers 6/
Customer-Owned Renewable Generation (0 kW to 10 kW)	111.06	158,164	416,346	49,639	524,871
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	42.70	60,374	293,892	14,885	339,381
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	28.59	82,547	294,557	7,560	369,544
Totals	182.35	301,085	1,004,795	72,084	1,233,797

1/ There were approximately 16,971 customers with renewable generation facilities interconnected with FPL on December 31, 2019.
2/ The Projected Annual Output value is based on NREL's PV Watts 1 program and uses the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
3/ The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2019.
4/ The Annual Energy Sold to FPL - Total is an actual value from FPL's metered data for 2019. These are the total MWh that were "overproduced" by the customer each month throughout 2019.
5/ The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL - Total).

Schedule 11.2: Gulf

Existing Non-Firm Self-Service Renewable Generation Facilities
Actuals for the Year 2019 1/

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh) 2/	Annual Energy Purchased from FPL (MWh) 3/	Annual Energy Sold to FPL - Total (MWh) 4/	Projected Annual Energy Used by Customers 5/
(All) Totals	18.85	27,676	19,339	6,821	40,195

1) Total count of renewable generation facilities as of 12/31/2019 = 2,229
2) Projected Annual Output value is based on NREL's PV Watts calculation assuming average annual kWh's per year at 1,468 for a (1) kW system
3) The Annual Energy Purchased from Gulf is an actual value from Gulf Power's metered data for 2019
4) The annual energy sold to Gulf Power - Total is an actual value from Gulf Power's metered data for 2019. These are the total MWh that were "overproduced" by the customer each month throughout 2019
5) The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to Gulf Power - Total)

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A. Protection of the Environment

Clean, affordable energy is the lifeblood of Florida's growing population, expanding economy, and environmental resource restoration and management. Through its commitment to environmental excellence, FPL and Gulf are helping to solve Florida's energy challenges sustainably and responsibly. With one of the cleanest, most efficient power-generation fleets in the nation, FPL has reduced its use of oil, including foreign oil, by approximately 98 percent – from approximately 40 million barrels annually in 2001 to 0.4 million barrels in 2019. FPL also has one of the lowest emissions profiles among U.S. utilities, and its carbon dioxide (CO_2) emission rate in 2019 was approximately 30% lower (cleaner) than the industry national average. Gulf has reduced its sulfur dioxide emissions by 99%, its nitrogen oxide (NOx) emissions by 81%, and its carbon dioxide emissions by 40%, from 2001 to 2018. FPL and Gulf together are also the largest producers of solar energy-generated electricity in Florida. At the end of 2019, FPL had approximately 1,228 MW of solar generation capability on its system which consists of approximately 1,153 MW of universal solar PV and 75 MW of solar thermal. Also at the end of 2019, Gulf has renewable energy purchase agreements for approximately 120 MW of universal solar PV generation and 81 MW of wind which is provided through multiple power purchase agreements (PPAs).

This 2020 Site Plan for FPL and Gulf presents a resource plan which shows a significant amount of additional solar. The merged system is projected to have approximately 10,000 MW of solar by the end of the 10-year reporting period (2029) for this Site Plan.

FPL and Gulf maintain their commitment to environmental stewardship through proactive collaboration with communities and organizations working to preserve Florida's unique habitat and natural resources. The many projects and programs in which FPL and Gulf actively participate include the creation and management of the Manatee Lagoon – An FPL Eco-Discovery Center, Everglades Mitigation Bank, Crocodile Management Program, and Longleaf pine restoration.

FPL, Gulf, and their parent company, NextEra Energy, Inc., have continuously been recognized as leaders among electric utilities for their commitment to the environment – a commitment that is ingrained in the corporate culture.

In 2020, Fortune ranked NextEra Energy, Inc. as No. 1 in the electric and gas utilities industry in their "2020 World's Most Admired Companies". The annual list recognizes companies that have had a positive social impact through activities that are part of their core business strategy. NextEra Energy was also named one of the "2020 World's Most Ethical Companies" by Ethisphere Institute which recognizes companies' critical roles in influencing and driving positive change in both the business community and societies around the world. NextEra Energy is one of only six companies worldwide in the energy and utilities sector to receive Ethisphere Institute's prestigious recognition in 2020.

NextEra Energy's Juno Beach, Florida, campus, which includes FPL's headquarters, has achieved the prestigious Leadership in Energy and Environmental Design (LEED) Gold certification for existing buildings and two Gulf facilities are also LEED certified. LEED is the U.S. Green Building Council's leading rating system for designating the world's greenest, most energy-efficient, and high-performing buildings. Key achievements that led to the certification include heating, ventilation and air conditioning improvements, lighting upgrades, water management and recycling programs, and changes to specifications for paper, carpet, and other materials.

FPL and Gulf are committed to environmentally sustainable water use. Nearly 98% of the water FPL uses is returned to its original source. Similarly, nearly 90% of the water Gulf uses is returned to its original source. Pursuing alternate water sources, such as the use of 13.9 million gallons per day of treated wastewater for cooling the FPL West County Energy Center and 1.8 million gallons per day at Gulf's Plant Crist, reduces the need to access ground or surface water resources.

IV.B Environmental Organization Contributions

In 2019, FPL supported a broad base of environmental organizations with donations, event sponsorships, and memberships. Those organizations include, but were not limited to: Everglades Foundation, The Nature Conservancy, Loggerhead Marinelife Center, Inc., Florida Wildflower Foundation, Florida State Parks Foundation, Florida Native Plant Society, Florida Wildlife Federation, Inwater Research Group, Defenders of Wildlife and Audubon state & local chapters. FPL employees serve in board and leadership positions for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Florida Fish and Wildlife Conservation Commission, The Nature Conservancy in Florida, Grassy Waters Conservancy, Loggerhead Marinelife Center, Everglades Foundation and Audubon Florida.

Gulf supports environmental organizations through financial contributions and volunteer hours. Every year Gulf employees invest an average of 1,200 volunteer hours supporting conservation partners in maintaining, restoring and protecting waters, wetlands, forests, beaches, parks, historic sites, and wildlife. In 2019, the Gulf Power Foundation Amplify! awarded a $40,000 grant to the Florida Wildlife Federation to assist large landowners near Panama City, Florida clean up and remove trees destroyed and damaged by Hurricane Michael in 2018 and restore their lands with longleaf pine trees. Other environmental organizations receiving financial contributions or volunteer hours in 2019 include, but are not limited to: The Nature Conservancy, E.O. Wilson Biophilia Center, FWC Scallop Restoration, Gulf Islands National Seashore, Eglin Air Force Base – Gopher Tortoise, Choctawhatchee Basin Alliance, Audubon Florida, and Walton County Dune Lake Restoration.

IV.C Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of energy efficiency, environmental awareness, and through public education. Some of FPL's 2019 environmental outreach activities are summarized in Table IV.E.1.

Table IV.C.1: 2019 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to Manatee Lagoon - An FPL Eco-Discovery Center	162,422
Number of website visits to Manatee Lagoon website, visitmanateelagoon.com	565,642
Visitors to Manatee Park, Ft. Myers	271,386
Number of website visits to FPL's Environmental & Corporate Sustainability Websites	>57,000
Visitors to FPL Living Lab, Martin Energy Center Solar & DeSoto Solar Tours	861
Environmental Brochures Distributed	~40,839
Home Energy Surveys	Field Visits: 19,587 Phone: 20,168 Online: 77,958 **Total: 117,713**

IV.D Environmental Policy

FPL, Gulf, and their parent company, NextEra Energy, Inc., are committed to remaining an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. This commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of its business planning, operations, and daily work.

In accordance with commitments to environmental protection and stewardship, FPL, Gulf, and NextEra Energy, Inc. endeavor to:

Comply:

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain facilities in an environmentally sound and responsible manner

Conserve:

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities
- Seek innovative solutions

Communicate:

- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance
- Communicate this policy to all employees and publish it on the corporate website

Continuously Improve:

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices

FPL and Gulf's parent company, NextEra Energy, Inc., updated this policy in 2020 to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL and Gulf comply with all environmental laws, regulations, and permit requirements, and they design, construct, and operate their facilities in an environmentally sound and responsible manner. FPL and Gulf also respond immediately and effectively to any known environmental hazards or non-compliance situations. The commitment to the environment does not end there. FPL and Gulf proactively pursue opportunities to perform better than current environmental standards require, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout their operations and day-to-day work activities. FPL and Gulf encourage cost-effective, efficient uses of energy, both within the Company and by their customers. These actions are just a few examples of how FPL and Gulf are committed to the environment.

To ensure FPL and Gulf are adhering to their environmental commitment, they have developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program. Through this program, FPL and Gulf conduct periodic environmental self-evaluations to verify that its operations comply with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.E Environmental Management

In order to successfully implement the Environmental Policy, FPL and Gulf have developed a robust Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program, which is described in section IV.F below. Other system components include: executive management support and commitment, dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.F Environmental Assurance Program

FPL and Gulf's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is an environmental audit. An environmental audit is defined as a management tool comprised of a systematic, documented, periodic, and objective evaluation of the performance of the organization and its specific management systems and equipment designed to protect the environment. An environmental audit's primary objective is to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and corporate policies. In addition to FPL and Gulf facility audits, through the Environmental Assurance Program, audits of third-party vendors used for recycling and/or disposal of waste generated by FPL and Gulf operations are performed. Vendor audits provide information used for selecting candidate or incumbent vendors for disposal and recycling needs.

In addition to periodic environmental audits, NextEra Energy Inc.'s Environmental Construction Compliance Assurance Program provides routine onsite inspections during construction and site-specific environmental training to everyone anticipated to be onsite during construction. Similar to an environmental audit, these inspections are performed to ensure compliance with the requirements of environmental permits, licenses, and corporate policies during the construction phase.

FPL and Gulf have also implemented a Corporate Environmental Governance System in which quarterly reviews are performed of each business unit deemed to have potential for significant environmental exposure. Quarterly reviews evaluate operations for potential environmental risks and consistency with the Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

IV.G Preferred and Potential Sites

Based upon projection of future resource needs and analyses of viable resource options, 26 Preferred Sites and 13 Potential Sites have been identified for adding future generation. Some of these sites currently have existing generation. Preferred Sites are those locations where significant reviews have taken place and action has either been taken, action is committed, or it is likely that action will be taken to site new generation. Potential Sites are those with attributes that would support the siting of generation and are under consideration as a location for future generation. The identification of a Potential Site does not necessarily indicate that a definitive decision to pursue new generation (or generation expansion or modernization in the case of an existing generation site) at that location has been made, nor does this designation necessarily indicate the that size or technology of a generating resource has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.G.1 Preferred Sites

For the 2020 Ten Year Site Plan, 26 Preferred Sites have been identified. These include a combination of existing and new sites in both the FPL and Gulf areas for the development of solar generation facilities, natural gas-fueled combined cycle and combustion turbine units, battery storage, and/or nuclear generation. Sites for a number of solar additions in 2020 and 2021 have been selected, and these sites are described in this section. Potential sites for possible 2022-on solar additions, plus other types of generation, are discussed in the Potential Site section later in this chapter.

These 26 Preferred Sites are listed in Table IV.G.1 below, and information regarding each site is then presented on the following pages. The sites are presented in general chronological order of when resources are projected to be added to the FPL and Gulf areas. The topographical features of each site, land use, and facility layout figures are provided at the end of this chapter.

Table IV.G.1: List of FPL & Gulf Preferred Sites

Site Name	County	Technology
FPL Area		
Hibiscus Solar Energy Center	Palm Beach	Solar
Okeechobee Solar Energy Center	Okeechobee	Solar
Southfork Solar Energy Center	Manatee	Solar
Echo River Solar Energy Center	Suwannee	Solar
Lakeside Solar Energy Center	Okeechobee	Solar
Trailside Solar Energy Center	St. Johns	Solar
Union Springs Solar Energy Center	Union	Solar
Magnolia Springs Solar Energy Center	Clay	Solar
Egret Solar Energy Center	Baker	Solar
Nassau Solar Energy Center	Nassau	Solar
Pelican Solar Energy Center	St. Lucie	Solar
Palm Bay Solar Energy Center	Brevard	Solar
Discovery Solar Energy Center	Brevard	Solar
Orange Blossom Solar Energy Center	Indian River	Solar
Sabal Palm Solar Energy Center	Palm Beach	Solar
Fort Drum Solar Energy Center	Okeechobee	Solar
Rodeo Solar Energy Center	DeSoto	Solar
Willow Solar Energy Center	Manatee	Solar
Manatee Energy Storage Center	Manatee	Battery
Sunshine Gateway Energy Storage Center	Columbia	Battery
Echo River Energy Storage Center	Suwanee	Battery
Dania Beach Clean Energy Center Unit 7	Broward	CC
Turkey Point Units 6&7	Miami-Dade	Nuclear
Gulf Area		
Blue Springs Solar Energy Center	Jackson	Solar
Chautauqua Solar Energy Center	Walton	Solar
Crist Unit 8	Escambia	CT

Preferred Site #1 Hibiscus Solar Energy Center, Palm Beach County

	Facility Acerage	**402**
	COD	**Q2 2020**
	For PV facilities: tracking or fixed	**Fixed**
		Reference Maps
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Abandoned citrus and pastureland
	Adjacent Areas	Residential, abandoned citrus, and pastureland
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site has minimal trees and is mostly comprised of herbaceous grasses. An existing network of irrigation canals is present.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar power generation is allowed within existing Agricultural land use designation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: August 22, 2018 Florida Environmental Resources Permit (ERP) received: February 13, 2018

Preferred Site #2 Okeechobee Solar Energy Center, Okeechobee County

	Facility Acerage	**471**
	COD	**Q2 2020**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pastureland and fallow crop land
	Adjacent Areas	Pastureland, conservation, and existing electrical transmission
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is comprised of pastureland, fallow citrus, pine Flatwoods, mixed forested wetlands, saw palmetto prairie, and freshwater marsh.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	The Okeechobee Solar site is adjacent to the Ft. Drum Marsh Conservation Area.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation includes agricultural production and power generation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: October 18, 2018 Florida Environmental Resources Permit (ERP) received: September 21, 2018 Okeechobee County Development Approval: July 24, 2018

Preferred Site #3 Southfork Solar Energy Center, Manatee County

	Facility Acerage	**548**
	COD	**Q2 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Agricultural production and fallow crop land
	Adjacent Areas	Agricultural production, forested and non-forested uplands
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately agricultural with some forested wetland areas.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar power generation is allowed within existing Agricultural land use designation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: November 13, 2018 Florida Environmental Resources Permit (ERP) received: September 21, 2018 Manatee County Site Plan Approval: February 6, 2019

Preferred Site #4 Echo River Solar Energy Center, Suwannee County

	Facility Acerage	**802**
	COD	**Q2 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation and pastureland
	Adjacent Areas	Pine plantation and pastureland
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation and pasture with forested and herbaceous wetland areas.
2.	Listed Species	Listed species known to occur include gopher tortoise. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	Rocky Creek runs through the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation includes agricultural production and power generation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the North Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: N/A Florida Environmental Resources Permit (ERP) received: September 14, 2018 Suwannee County Development Approval: May 15, 2018

Preferred Site #5 Lakeside Solar Energy Center, Okeechobee County

	Facility Acerage	**693**
	COD	**Q4 2020**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pastureland
	Adjacent Areas	Pastureland, low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly comprised of pastureland with freshwater herbaceous wetlands, drainage ditches, and a retention pond.
2.	Listed Species	Listed species known to occur onsite include Audubon's crested caracara, gopher tortoise and Florida burrowing owl. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	The Lakeside Solar site is adjacent to the Nubbin Slough and the Nubbin Slough Stormwater Treatment Area, which ultimately discharge to Lake Okeechobee, an Outstanding Florida Water.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. The project has been designed to maximize use of existing uplands to avoid wetland and surface water impacts. Therefore, no compensatory mitigation is required for this site.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Rural Estate.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants. Vegetated Natural Buffers will be incorporated adjacent to access paths to treat stormwater runoff.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: N/A Florida Environmental Resources Permit (ERP) received: February 15, 2019 Okeechobee County Development Approval: November 9, 2018

Preferred Site #6 Trailside Solar Energy Center, St. Johns County

	Facility Acerage	**846**
	COD	**Q4 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine Plantation
	Adjacent Areas	Open Rural
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly comprised of pine plantation with freshwater forested wetlands.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat no impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	Florida Forever Board of Trustees project as the Matanzas to Ocala Conservation Corridor is located at the southeast corner.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Compensatory mitigation for unavoidable wetland impacts will be accomplished through purchase of credits from Sundew Mitigation Bank.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agriculture.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: January 31, 2019 Florida Environmental Resources Permit (ERP) received: February 7, 2019 St. John's County Development Approval: November 15, 2018 (SUP) and December 12, 2018 (NZV)

Preferred Site #7 Union Springs Solar Energy Center, Union County

	Facility Acerage	**725**
	COD	**Q2 2021**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation
	Adjacent Areas	Pine plantation and pine processing facility
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation with forested and herbaceous wetland areas.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agricultural.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	Florida Environmental Resources Permit (ERP) received: December 19, 2018 USACE Section 404 received: N/A Union County Site Plan Approval: Pending Union County Special Use Exception received: July 16, 2018

Preferred Site #8 Magnolia Springs Solar Energy Center, Clay County

	Facility Acerage	**850**
	COD	**Q4 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation
	Adjacent Areas	Pine plantation and low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation with forested wetland areas.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agricultural and Conservation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	Florida Environmental Resources Permit (ERP) received: February 18, 2019 USACE Section 404 received: N/A Clay County Comprehensive Plan Amendment Approval: October 23, 2018 Clay County Site Plan Approval: Pending

Preferred Site #9 Egret Solar Energy Center, Baker County

	Facility Acerage	**676**
	COD	**Q3 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation
	Adjacent Areas	Pine plantation and low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation with forested and herbaceous wetland areas.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agricultural.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	Florida Environmental Resources Permit (ERP) received: pending USACE Section 404 received: pending Baker County Special Use Approval: pending

Preferred Site #10 Nassau Solar Energy Center, Nassau County

	Facility Acerage	**927**
	COD	**Q1 2021**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation
	Adjacent Areas	Pine plantation and low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation with forested wetland areas.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Industrial.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	Florida Environmental Resources Permit (ERP) received: August 1, 2019 USACE NW51 Verification received: June 12, 2019 Nassau County Site Plan Approval: September 24, 2019

Preferred Site #11 Pelican Solar Energy Center, St. Lucie County

	Facility Acerage	**564**
	COD	**Q1 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Citrus groves
	Adjacent Areas	Citrus groves, fallow cropland
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly citrus groves with agricultural drainage ditches and a spoil area.
2.	Listed Species	Listed species known to forage within surrounding area include Audubon's crested caracara. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, stormwater system and off-site transmission substation. The project has been designed to maximize use of existing uplands to avoid wetland and surface water impacts. Therefore, no compensatory mitigation is required for this site.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agricultural.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants. Vegetated Natural Buffers will be incorporated adjacent to access paths to treat stormwater runoff.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: N/A Florida Environmental Resources Permit (ERP) received: April 29, 2019 St. Lucie County Development Approval: August 13, 2019

Preferred Site #12 Palm Bay Solar Energy Center, Brevard County

	Facility Acerage	**486**
	COD	**Q2 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Cleared citrus grove that is currently in use as cattle pasture
	Adjacent Areas	Agricultural, forested uplands and wetlands, and single-family residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly comprised of agricultural land with freshwater herbaceous wetlands and drainage ditches.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Rural Residential.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: 7/12/2019 Florida Environmental Resources Permit (ERP) received: 5/21/2019 City of Palm Bay Development Approval: Pending

Preferred Site #13 Discovery Solar Energy Center, Brevard County

	Facility Acerage	**491**
	COD	**Q1 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Undeveloped former citrus grove
	Adjacent Areas	Undeveloped and industrial
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately abandoned citrus groves, ditches and scattered freshwater forested and herbaceous wetlands which are now dominated by invasive, exotic vegetation.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, no impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	The site is adjacent to the Merritt Island National Refuge and adjacent to the Indian River Lagoon.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Compensatory mitigation for unavoidable wetland impacts will be accomplished through purchase of credits from NeoVerde Mitigation Bank.
h.	**Local Government Future Land Use Designations**	Site is federal land and therefore exempt from local zoning.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for PV Process: Not applicable for PV Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: Pending Florida Environmental Resources Permit (ERP) received: October 24, 2019 Brevard County Site Plan Approval: N/A

Preferred Site #14 Orange Blossom Solar Energy Center, Indian River County

	Facility Acerage	**607**
	COD	**Q2 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Citrus grove
	Adjacent Areas	Citrus groves, fallow cropland
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly a citrus grove with canals/ditches. The site likely contains no jurisdictional wetlands.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is citrus, plant crops, and grazing.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: N/A Florida Environmental Resources Permit (ERP) received: 4/26/2019 Indian River County Approval: 8/13/2019

Preferred Site #15 Sabal Palm Solar Energy Center, Palm Beach County

	Facility Acerage	**646**
	COD	**Q1 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Fallow Agricultural Production
	Adjacent Areas	Agriculture, single-family residential, vacant land
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominantly comprised of fallow agricultural land with freshwater herbaceous wetlands and drainage ditches.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, no impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Compensatory mitigation for unavoidable wetland impacts will be accomplished through purchase of credits from Bluefield Ranch Mitigation Bank.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Rural Residential.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: Pending Florida Environmental Resources Permit (ERP) received: Pending Palm Beach County Development Approval: October 25, 2019

Preferred Site #16 Fort Drum Solar Energy Center, Okeechobee County

	Facility Acerage	**930**
	COD	**Q2 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pastureland and fallow crop land
	Adjacent Areas	Pastureland, conservation, and existing electrical transmission
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is comprised of pastureland, fallow citrus, pine Flatwoods, mixed forested wetlands, saw palmetto prairie, and freshwater marsh.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	The Fort Drum Solar site is near the Ft. Drum Marsh Conservation Area.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation includes agricultural production and power generation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE NW51 Verification: Pending Florida Environmental Resources Permit (ERP) received: Pending Okeechobee County Development Approval: Pending

Preferred Site #17 Rodeo Solar Energy Center, Desoto County

	Facility Acerage	**1193**
	COD	**Q1 2021**
	For PV facilities: tracking or fixed	**Tracking**
		Reference Maps
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Pastureland
	Adjacent Areas	Utilities (solar), cropland and pastureland
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	The site is comprised of pastureland, freshwater herbaceous and forested wetlands, pine Flatwoods, shrub and brushland, and other open land.
2.	Listed Species	Listed species known to occur onsite include Audubon's crested caracara and gopher tortoise. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	The site discharges to Sand Gully and Fish Branch, tributary to the Peace River, a Class lll Florida water.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. The project has been designed to maximize use of existing uplands to avoid wetland impacts and minimize surface water impacts. Therefore, no compensatory mitigation is required for this site.
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Rural/Agricultural.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: N/A Florida Environmental Resources Permit (ERP) received: December 23, 2019 DeSoto County Development Approval: Pending

Preferred Site #18 Willow Solar Energy Center, Manatee County

	Facility Acerage	**812**
	COD	**Q2 2021**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Abandoned agricultural
	Adjacent Areas	Cropland and pastureland
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately fallow cropland with drainage ditches/canals. Forested, herbaceous, and shrub marsh wetland areas are also present.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation
h.	**Local Government Future Land Use Designations**	Local government future land use for this site is Agriculture.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: Pending Florida Environmental Resources Permit (ERP) received: Pending Manatee County Approval: Pending

Preferred Site #19 Manatee Energy Storage Center, Manatee County

	Facility Acerage	**40**
	COD	**Q4 2021**
	For PV facilities: tracking or fixed	**N/A**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Utility power generation
	Adjacent Areas	Utility power generation and agricultural production
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation with few forested and herbaceous wetland areas.
2.	Listed Species	No adverse impacts are expected due to previous development and lack of suitable onsite habitat for listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 400MW, 2.5 hour Battery Storage facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation is Utilities, requiring modification to include Battery Storage.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Groundwater will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Central Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Battery Storage Process: Not Applicable for Battery Storage Potable: Minimal, existing permitted supply Panel Cleaning: Not applicable for Battery Storage
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Battery Storage Process: Not Applicable for Battery Storage Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Battery Storage does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Battery Storage does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - Battery Storage energy does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	Battery Storage energy does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: Not yet filed. Florida Environmental Resources Permit (ERP) received: Not yet filed. Manatee County PUD Zoning amendment: Pending

Preferred Site #20 Sunshine Gateway Energy Storage Center, Columbia County

	Facility Acerage	**30**
	COD	**Q4 2021**
	For PV facilities: tracking or fixed	**Fixed**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Agricultural production
	Adjacent Areas	Agricultural production and residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately agricultural with minimal forested wetlands and freshwater marshes.
2.	Listed Species	Listed species known to occur include gopher tortoise. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW of battery storage and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation includes agricultural production and power generation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for Battery Storage Process: Not applicable for Battery Storage Potable: Minimal, existing permitted supply Panel Cleaning: Not applicable for Battery Storage
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Battery Storage Process: Not Applicable for Battery Storage Potable and Panel Cleaning: Not applicable for Battery Storage
n.	**Water Conservation Strategies Under Consideration**	Battery Storage does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Battery Storage does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - Battery Storage energy does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	Battery Storage does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit expected: Q3 2020 Florida Environmental Resources Permit (ERP) Modification: expected Q3 2020 Suwannee County Development Approval: Expected April 2020

Preferred Site #21 Echo River Energy Storage Center, Suwannee County

	Facility Acerage	**5**
	COD	**Q4 2021**
	For PV facilities: tracking or fixed	**Tracker**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine plantation and pastureland
	Adjacent Areas	Pine plantation and pastureland
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately pine plantation and pasture with forested and herbaceous wetland areas.
2.	Listed Species	Listed species known to occur include gopher tortoise. No adverse impacts are anticipated to listed species.
3.	Natural Resources of Regional Significance Status	Rocky Creek runs through the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW of battery storage and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Local government future land use designation includes agricultural production and power generation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not applicable for Battery Storage Process: Not applicable for Battery Storage Potable: Minimal, existing permitted supply Panel Cleaning: Not applicable for Battery Storage
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Battery Storage Process: Not Applicable for Battery Storage Potable and Panel Cleaning: Not applicable for Battery Storage
n.	**Water Conservation Strategies Under Consideration**	Battery Storage does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Battery Storage does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - Battery Storage energy does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	Battery Storage does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	Florida Environmental Resources Permit (ERP) modification expected April 2020 Suwannee County Development Approval: Expected April 2020

Preferred Site #22 Dania Beach Clean Energy Center Unit 7, Broward County

	Facility Acerage	**134**
	COD	**Q2 2022**
	For PV facilities: tracking or fixed	**N/A**
		Reference Maps
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Electrical generating facilities
	Adjacent Areas	Low to high density urban, transportation, communication, utilities, commercial, water, and conservation
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site is comprised of facilities related to power generation.
2.	Listed Species	Listed species known to occur within the cooling pond at the site include the West Indian manatee. No adverse impacts are anticipated to listed species due to previous development.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The project includes dismantlement of existing Units 4 & 5 and replacement with one new approximately 1,163 MW combined cycle unit consisting of two combustion turbines (CTs), two heat recovery steam generators (HRSGs), and a steam turbine. The CTs will operate using natural gas and Ultra-Low Sulfur Distillate.
h.	**Local Government Future Land Use Designations**	The site is zoned General Industrial.
i.	**Site Selection Criteria Factors**	The Lauderdale Plant has been selected as a preferred site for a site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing, outdated combined cycle units with a new highly efficient combined cycle unit, including a significant reduction in system air emissions. In addition, the modernization project at this existing site will not require a new gas pipeline and will make use of the existing transmission facilities and water supply.
j.	**Water Resources**	Condenser cooling for the steam cycle portion of the new combined cycle unit and auxiliary cooling will come from the existing cooling water intake system. Process and potable water for the new unit will come from the existing water supply sources (Broward County and City of Hollywood).
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: No additional water required. Process: No additional water required. Potable: No additional water required. Panel Cleaning: Not Applicable
m.	**Water Supply Sources by Type**	Cooling: As existing, Dania Cut-Off Canal Process: As existing, Broward County Utilities Potable: As existing, City of Hollywood
n.	**Water Conservation Strategies Under Consideration**	No additional water resources are required beyond current usage.
o.	**Water Discharges and Pollution Control**	Continued discharge to the existing cooling pond is anticipated. No increase in water discharge is expected. Best Management Practices will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Natural gas will be transported via an existing pipeline. ULSD will be trucked to the facility and stored in existing ULSD tanks.
q.	**Air Emissions and Control Systems**	Fuel - Use of cleaner natural gas and Ultra-Low Sulfur Distillate • Natural Gas - Dry-low NOx combustion technology and Selective Catalytic Reduction will control NOx emissions, Greenhouse gas emissions will be substantially lower than the Environmental Protection Agency's proposed new source performance standard. • ULSD - Water injection and selective catalytic reduction will be used to reduce NOx emissions Combustion Control - will minimize formation of sulfur dioxide, particulate matter, nitrogen oxides (NOx), and other fuel-bound contaminate Combustor Design - will limit formation of carbon monoxide and volatile organic compounds
r.	**Noise Emissions and Control Systems**	Noise from the operation of the new unit will be within allowable levels.
s	**Status of Applications**	Need Determination Issued: March 19, 2018 FL Site Certification Received: December 13, 2018 PSD Permit Received: December 4, 2017 USACE Section 404 Permit Received: January 7, 2019 IWW Received: December 3, 2018

Preferred Site #23 Turkey Point Unit 6&7, Miami-Dade County

	Facility Acerage	**N/A**
	COD	**TBD**
	For PV facilities: tracking or fixed	**N/A**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Electrical generating facilities
	Adjacent Areas	Undeveloped, the Everglades Mitigation Bank, South Florida Water Management District Canal L-31E, Biscayne Bay, and state-owned land on Card Sound
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site includes hypersaline mud flats, man-made active cooling canals and remnant canals, previously filled areas / roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water / discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.
2.	Listed Species	Listed species known to occur at the site or associated linear features include the peregrine falcon, wood stork, American crocodile, roseate spoonbill, little blue heron, snowy egret, American oystercatcher, least tern, white ibis, Florida manatee, eastern indigo snake, snail kite, and white-crowned pigeon. Some listed flora species likely to occur include pine pink, Florida brickell-bush, Florida lantana, mullein nightshade, and Lamarck's trema. The construction and operation of Turkey Point Units 6 & 7 are not expected to adversely affect any listed species.
3.	Natural Resources of Regional Significance Status	Significant features in the vicinity of the site include Biscayne Bay, Biscayne National Park, Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The technology proposed is the Westinghouse AP1000 pressurized water reactor. This design is certified by the Nuclear Regulatory Commission under 10 CFR 52. The Westinghouse AP1000 consists of the reactor, steam generators, pressurizer, and steam turbine / electric generator. The projected generating capacity from each unit is 1,100 MW. Condenser cooling will use six circulating water cooling towers. The structures to be constructed include the containment building, shield building, auxiliary building, turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect to FPL's transmission system.
h.	**Local Government Future Land Use Designations**	Current future land use designations include Industrial, Utilities, Communications, and Unlimited Manufacturing with a dual designation of Mangrove Protection Area. There are also areas of the site designated Interim District.
i.	**Site Selection Criteria Factors**	Site selection included the following criteria: existing transmission and transportation infrastructure to support new generation, the size and seclusion of the site while being relatively close to the load center, economics, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.
j.	**Water Resources**	Water requirements will be met by reclaimed water from Miami-Dade County and a back-up supply of saline groundwater from below the marine environment of Biscayne Bay.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: 55.3 million gallons per day (mgd) Process: 1.3 mgd Potable: .05 mgd Panel Cleaning: Not Applicable
m.	**Water Supply Sources by Type**	Cooling: Miami-Dade reclaimed water and saline groundwater from Biscayne Bay via radial collector wells Process: Miami-Dade Water and Sewer Department Potable: Miami-Dade Water and Sewer Department
n.	**Water Conservation Strategies Under Consideration**	Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.
o.	**Water Discharges and Pollution Control**	Blowdown water or discharge from the cooling towers, along with other waste streams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	The Turkey Point Units 6 & 7 reactors will contain enriched uranium fuel assemblies. New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the permitted spent fuel pool while short half-life isotopes decay. After a sufficient decay period, the fuel would be transferred to a permitted on-site independent spent fuel storage installation facility or a permitted off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material. The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.
q.	**Air Emissions and Control Systems**	Fuel - The units will minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. Combustion Control / Combustor Design - Not Applicable Note: The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards Subpart IIII emission limits.
r.	**Noise Emissions and Control Systems**	Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.
s	**Status of Applications**	Need Determination Issued: April 2008 FL Site Certification Received: May 14, 2014 USACE Section 404 Permit: December 18, 2019 COL received: April 5, 2018 Miami-Dade County Unusual Use approvals: issued in 2007 and 2013 Land Use Consistency Determination: issued in 2013 Prevention of Significant Deterioration: issued in 2009

Preferred Site #24 Blue Springs Solar Energy Center, Jackson County

	Facility Acerage	**444**
	COD	**Q4 2020**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Agricultural crops
	Adjacent Areas	Agricultural and low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is predominately cropland with few forested uplands and wetlands
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	0
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar fixed panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar power generation is allowed within existing Agricultural land use designation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	**Status of Applications**	USACE Section 404 Permit received: NA Florida Environmental Resources Permit (ERP) received: February 26, 2019

Preferred Site #25 Chautauqua Solar Energy Center, Walton County

	Facility Acerage	**868**
	COD	**Q4 2021**
	For PV facilities: tracking or fixed	**Tracking**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Agricultural crops and pastureland
	Adjacent Areas	Agricultural and low density residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is predominately agricultural with some forested uplands and wetlands.
2.	Listed Species	Due to the existing disturbed nature of the site and lack of suitable onsite habitat, minimal, if any, impacts will occur to listed species.
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	Gulf and FPL are not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through a combination of on- and off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar power generation is allowed within existing Agricultural land use designation.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal, existing permitted supply Panel Cleaning: Minimal and only in absence of sufficient rainfall.
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Delivered to Site by Truck or via existing permitted supply.
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	0
s	**Status of Applications**	USACE Permit received: NA Florida Environmental Resources Permit (ERP): pending, application filed

Preferred Site #26 Crist Unit 8, Escambia County

	Facility Acerage	**58**
	COD	**Q4 2021**
	For PV facilities: tracking or fixed	**N/A**
	Reference Maps	
a.	**USGS Map**	See Figures at the end of this chapter
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Industrial (Electrical Generating Facility)
	Adjacent Areas	Public, Low & Medium Density Residential
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	The site is located in uplands within existing fenced plant property and consists of primarily of a pine and hardwood mix. The site has historically had silviculture operations.
2.	Listed Species	No adverse impacts to listed species are anticipated. However, Gopher Tortoise do occur in local area.
3.	Natural Resources of Regional Significance Status	Drainage from the site ultimately discharges into the Escambia river.
4.	Other Significant Features	Gulf is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes construction of four 235 MW combustion turbines, a switchyard, and associated wastewater and stormwater management systems. The site location has been selected in uplands with a significant buffer to any sensitive habitats. Final grading has been designed to match natural grades.
h.	**Local Government Future Land Use Designations**	The site is zoned General Industrial.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Groundwater will be used to meet water requirements.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter site is located in the Panhandle Florida region.
l.	**Project Water Quantities for Various Uses**	NOx control: 1.95 MGD during fuel oil operations Process: 1.9 MGD Potable:0.01 MGD
m.	**Water Supply Sources by Type**	Process: Exiting permitted groundwater usage; Potable: Emerald Coast Utilities Authority
n.	**Water Conservation Strategies Under Consideration**	No additional water resources are required beyond currently permitted usage.
o.	**Water Discharges and Pollution Control**	The existing Plant Crist industrial wastewater treatment system will be utilized for the project. A new stormwater management system will be constructed to ensure the post development discharge rate is not greater than the predevelopment conditions. Best management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Natural gas will be transported via a new pipeline. Ultra Low Sulfur Distillate (ULSD) will be trucked to the facility and stored in a new ULSD tank.
q.	**Air Emissions and Control Systems**	Fuel - Use of cleaner natural gas and Ultra-Low Sulfur Distillate • Natural Gas - Dry-low NOx combustion technology will control NOx emissions, Greenhouse gas emissions will be substantially lower than the Environmental Protection Agency's proposed new source performance standard. • ULSD - Water injection will be used to reduce NOx emissions Combustion Control - will minimize formation of sulfur dioxide, particulate matter, nitrogen oxides (NOx), and other fuel-bound contaminate Combustor Design - will limit formation of carbon monoxide and volatile organic compounds
r.	**Noise Emissions and Control Systems**	Noise from the operation of the new unit will be within allowable levels.
s	**Status of Applications**	USACE Jurisdictional Determination Received: September 20, 2019 ERP Permit Received: October 14, 2019 UIC Permit Received: October 25, 2019 PSD Permit Received: February 5, 2020 IWW Permit Revision: In Progress

IV.G.2 Potential Sites

There are 13 Potential Sites that have currently been identified for future generation and storage additions to meet projected capacity and energy needs.[15] Each of these Potential Sites offers a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that would require further definition and attention. Unless otherwise noted, the water quantities discussed below are in reference to universal solar PV generation rather than for gas-fueled generation.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. At this time, FPL and Gulf consider each site to be equally viable. The Potential Sites briefly discussed below are presented in alphabetical order of Site name for those in FPL's area and by name of County for those in Gulf's area.

Table IV.G.2: List of FPL & Gulf Potential Sites

Site Name	County	Technology
FPL Area		
Elder Branch	Manatee	Solar
Everglades	Miami-Dade	Solar
Ghost Orchid	Hendry	Solar
Sawgrass	Hendry	Solar
Sundew	St Lucie	Solar
White Tail	Martin	Solar
Gulf Area		
TBD	Calhoun	Solar
TBD	Calhoun	Solar
TBD	Escambia	Solar
TBD	Gadsden	Solar
TBD	Jackson	Solar
TBD	Okaloosa	Solar
TBD	Santa Rosa	Solar

[11] As has been described in previous FPL Site Plans, a number of other locations are also possible sites for future generation additions. These include the remainder of FPL's and Gulf's existing generation sites and other greenfield sites. Specific greenfield sites may not be specifically identified as Potential Sites in order to protect the economic interests of the utility and its customers.

FPL Area Potential Site # 1: Elder Branch

This potential site in Manatee County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily fallow crop land surrounded by agricultural land, low density residential, and conservation lands.

c. Environmental Features

Site is predominately fallow cropland with some forested wetland. Site is located adjacent to publicly owned conservation lands. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Minimal for PV.
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Not Applicable for PV.
Panel Cleaning: Trucked in if and when needed for PV.

FPL Area Potential Site # 2: Everglades

This potential site in Miami-Dade County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily agricultural land surrounded by other agricultural lands.

c. Environmental Features

Site is agricultural land with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Minimal for PV.
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Not Applicable for PV.
Panel Cleaning: Trucked in if and when needed for PV.

FPL Area Potential Site # 3: Ghost Orchid

This potential site in Hendry County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Existing land use is primarily agricultural and surrounded by predominately agricultural and low density residential.

c. Environmental Features

Site is predominately agricultural with some forested wetlands with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

FPL Area Potential Site # 4: Sawgrass

This potential site in Hendry County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pastureland and surrounded by agricultural lands and forested wetlands.

c. Environmental Features

Site is predominately pastureland with a mosaic of forested wetlands throughout the site. Subject property is located almost entirely within the primary panther zone. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

FPL Area Potential Site # 5: Sundew

This potential site in St. Lucie County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily Improved pasture and fallow citrus groves surrounded by agricultural lands.

c. Environmental Features

Site is improved pasture and fallow citrus with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

FPL Area Potential Site # 6: White Tail

This potential site in Martin County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is predominately fallow cropland surrounded by agricultural lands.

c. Environmental Features

Site is mostly fallow cropland with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 1: Calhoun County

A potential site in Calhoun County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation surrounded by pine plantation and low density residential.

c. Environmental Features

Site is predominately pine plantation with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 2: Calhoun County

Another potential site in Calhoun County is also under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation and pastureland surrounded by agricultural land and low density residential.

c. Environmental Features

Site is predominately agricultural with some forested uplands and wetlands and no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Minimal for PV.
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.
Process: Not Applicable for PV.
Potable: Not Applicable for PV.
Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 3: Escambia County

A potential site in Escambia County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation surrounded by other pine plantations and pastureland.

c. Environmental Features

Site is predominately pine plantation with forested wetlands and no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 4: Gadsden County

A potential site in Gadsden County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation surrounded by pine plantation and forested wetlands.

c. Environmental Features

Site is predominately pine plantation with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 5: Jackson County

A potential site in Jackson County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site primarily pine plantation surrounded by pastureland and low density residential.

c. Environmental Features

Site is predominately pine plantation with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 6: Okaloosa County

A potential site in Okaloosa County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation with some pastureland and is surrounded by agricultural lands and low density residential.

c. Environmental Features

Site is predominately pine plantation with forested uplands and some pastureland with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Gulf Area Potential Site # 7: Santa Rosa County

A potential site in Santa Rosa County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily pine plantation surrounded by pine plantations and low density residential.

c. Environmental Features

Site is predominately pine plantation with no significant environmental features on or nearby this site. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal for PV.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Not Applicable for PV.

Panel Cleaning: Trucked in if and when needed for PV.

Duke Energy Florida, LLC
Ten-Year Site Plan

April 2020

2020-2029

Submitted to:
Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 16
PARTY: KRR-5
DESCRIPTION: Duke Energy Florida, LLC Ten Year Site Plan

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LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined Cycle
SPP - Small Power Producer
COG - Cogeneration Facility
PV - Photovoltaic

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO – Biomass
SO – Solar PV

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. Duke Energy Florida, LLC's (DEF)'s TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

DEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning DEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**

  This chapter provides an overview of DEF's generating resources as well as the transmission and distribution system.

- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**

  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.

- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**

  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.

- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**

  Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, LLC (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.83 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of Saint Petersburg and Clearwater. DEF is interconnected with 21 municipal and nine rural electric cooperative systems who serve additional customers in Florida. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF transmission system includes approximately 5,200 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 14,000 circuit miles of underground distribution cable.

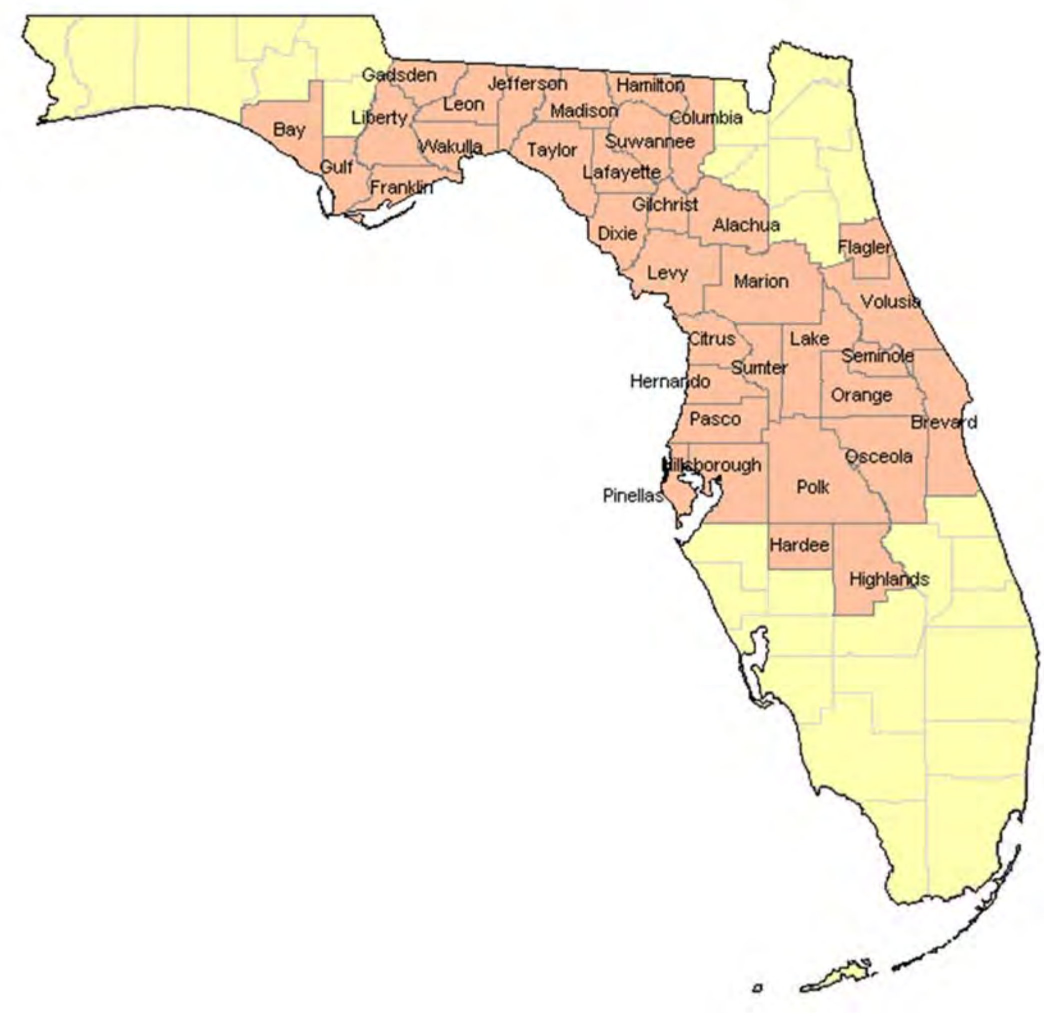
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 439,000 customers participated in the residential Energy Management program during 2019, contributing about 711 MW of winter peak-shaving capacity for use during high load periods. DEF's currently approved DSM programs consist of five residential programs, six commercial and industrial programs and one research and development program.

TOTAL CAPACITY RESOURCE

As of December 31, 2019, DEF had total summer capacity resources of 11,858 MW consisting of installed capacity of 9,902 MW and 1,956 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2019

(1) PLANT NAME	(2) UNIT NO.	(3) LOCATION (COUNTY)	(4) UNIT TYPE	(5) FUEL PRI.	(6) FUEL ALT.	(7) FUEL TRANSPORT PRI.	(8) FUEL TRANSPORT ALT.	(9) ALT. FUEL DAYS USE	(10) COM'L IN-SERVICE MO./YEAR	(11) EXPECTED RETIREMENT MO./YEAR	(12) GEN. MAX. NAMEPLATE KW	(13) NET CAPABILITY SUMMER MW	(14) NET CAPABILITY WINTER MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	498	511
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	505	514
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	710	721
											Steam Total	**2,425**	**2,467**
COMBINED-CYCLE													
P L BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	*	6/09		1,254,200	1,144	1,227
CITRUS COUNTY COMBINED CYCLE	PB1	CITRUS	CC	NG		PL			10/18		985,150	816	931
CITRUS COUNTY COMBINED CYCLE	PB2	CITRUS	CC	NG		PL			11/18		985,150	816	931
HINES ENERGY COMPLEX	1	POLK	CC	NG		PL			4/99		546,500	490	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	*	12/03		548,250	524	563
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	*	11/05		561,000	515	553
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	*	12/07		610,500	516	544
OSPREY ENERGY CENTER POWER PLANT	1	POLK	CC	NG		PL			5/04		644,300	245	245
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	200	231
											CC Total	**5,266**	**5,753**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	*	12/68	10/2020 **	33,750	24	25
AVON PARK	P2	HIGHLANDS	GT	DFO		TK		*	12/68	10/2020 **	33,750	24	25
BARTOW	P1	PINELLAS	GT	DFO		WA		*	5/72	6/2027 **	55,400	41	52
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	*	6/72		55,400	41	57
BARTOW	P3	PINELLAS	GT	DFO		WA		*	6/72	6/2027 **	55,400	41	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	*	6/72		55,400	45	61
BAYBORO	P1	PINELLAS	GT	DFO		WA		*	4/73	12/2025 **	56,700	44	61
BAYBORO	P2	PINELLAS	GT	DFO		WA		*	4/73	12/2025 **	56,700	41	58
BAYBORO	P3	PINELLAS	GT	DFO		WA		*	4/73	12/2025 **	56,700	43	60
BAYBORO	P4	PINELLAS	GT	DFO		WA		*	4/73	12/2025 **	56,700	43	59
DEBARY	P2	VOLUSIA	GT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	48	64
DEBARY	P3	VOLUSIA	GT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	50	65
DEBARY	P4	VOLUSIA	GT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	50	65
DEBARY	P5	VOLUSIA	GT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	50	65
DEBARY	P6	VOLUSIA	GT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	51	65
DEBARY	P7	VOLUSIA	GT	NG	DFO	PL	TK	*	10/92		103,500	79	99
DEBARY	P8	VOLUSIA	GT	NG	DFO	PL	TK	*	10/92		103,500	78	96
DEBARY	P9	VOLUSIA	GT	NG	DFO	PL	TK	*	10/92		103,500	80	98
DEBARY	P10	VOLUSIA	GT	DFO		TK		*	10/92		103,500	75	95
INTERCESSION CITY	P1	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	47	64
INTERCESSION CITY	P2	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	46	63
INTERCESSION CITY	P3	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	46	63
INTERCESSION CITY	P4	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	46	63
INTERCESSION CITY	P5	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	45	62
INTERCESSION CITY	P6	OSCEOLA	GT	DFO		PL,TK		*	5/74		56,700	47	64
INTERCESSION CITY	P7	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	10/93		103,500	78	95
INTERCESSION CITY	P8	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	10/93		103,500	79	96
INTERCESSION CITY	P9	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	10/93		103,500	79	96
INTERCESSION CITY	P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	10/93		103,500	78	96
INTERCESSION CITY	P11	OSCEOLA	GT	DFO		PL,TK		*	1/97		148,500	140	161
INTERCESSION CITY	P12	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	94
INTERCESSION CITY	P13	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	12/00		98,260	75	93
INTERCESSION CITY	P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	*	12/00		98,260	72	92
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	DFO	PL	TK	*	10/80		65,999	49	68
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK		*	10/80		65,999	50	67
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	DFO	PL	TK	*	11/80		65,999	50	68
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	NG		PL			1/94	11/2027 **	43,000	44	46
											CT Total	**2,092**	**2,674**
SOLAR													
OSCEOLA SOLAR FACILITY	PV1	OSCEOLA	PV	SO					5/16		3,800	2	0
PERRY SOLAR FACILITY	PV1	TAYLOR	PV	SO					8/16		5,100	2	0
SUWANNEE RIVER SOLAR FACILITY	PV1	SUWANNEE	PV	SO					11/17		8,800	4	0
HAMILTON SOLAR FACILITY	PV1	HAMILTON	PV	SO					12/18		74,900	42	0
TRENTON SOLAR FACILITY	PV1	GILCHRIST	PV	SO					12/19		74,900	43	0
LAKE PLACID	PV1	HIGHLANDS	PV	SO					12/19		45,000	26	0
ST PETERSBURG	PV1	PINELLAS	PV	SO					12/19		350	0.2	0
											SOLAR Total	**119**	**0**
											TOTAL RESOURCES (MW)	**9,902**	**10,894**

* APPROXIMATELY 2 TO 3 DAYS OF OIL USE TYPICALLY TARGETED FOR ENTIRE PLANT.
** DATES FOR RETIREMENT ARE APPROXIMATE AND SUBJECT TO CHANGE

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). In general, this discussion refers to DEF's base forecast. Economic data from 2019 reflected a national economy continuing and surpassing the record for longest expansion in U.S. history albeit with modest to slow overall growth. Growth in 2019 slowed compared to 2018 due to fading effects from the tax cuts, a weakening global economy, and disruptions from international trade policy. The 2019 performance was somewhat buoyed by the Federal Reserve decision to defer proposed increases to interest rates during the year.

The 2020 outlook calls for slower U.S. economic growth as the trends of 2019 continue. Looking ahead, the projections incorporated in this site plan forecast a moderation of growth rates in population and economic activity within the U.S. and DEF service territory as assumed in the Moody's Analytics July 2019 projection. DEF continues to provide alternate "high" and "low" forecasts for energy and demand growth, recognizing that the current economic expansion may continue to accelerate or could unwind due to an unexpected economic imbalance or Global political event.

Over the course of the ten years of history in this Site Plan (2010-2019), the nation and the State of Florida have endured the worst economic downturn in eighty years and have emerged to set the record for longest economic recovery. Economic measures appear to have returned to normal pre-crisis levels for both the U.S. and Florida economies. A strong recovery has taken place in the past few years and the Florida economy can be expected to experience more normal rates of growth as the current economic expansion nears full employment. More business investment and increased productivity will be required to hold off rising inflation and higher interest rates. The Federal Reserve will have its work cut out maintaining this balance. County population growth rate projections from the University of Florida's Bureau of Economic and Business Research (BEBR) were incorporated into this projection. The DEF service area population has been estimated to have grown at an average ten-year growth of 1.22% from 2010 – 2019 (Schedule 2.1.1 Column 2). Demographic conditions going forward look amenable to sustaining a level of growth closer to 1.25% over the 2020-2029 period. The rate of residential customer growth, which averaged 1.27% per year over the historical ten-year period, is expected to improve to an average of 1.43% for the projected ten years. A projected decline in average household size will result in a higher rate of household growth. By looking at Schedule 2.3.1 Column 6, we find that total DEF customers grew from 1.641 million in 2010 to 1.833 million in 2019, an increase of 192,052 or 1.24% annual growth rate. The projected number of total customers between 2020 and 2029 is 246,321 or 1.39% annual growth rate. The DEF service area projected ten-year average population growth is expected to remain elevated from the previous 10 years mainly due to the large baby-boom age cohort retiring to sunny Florida.

From 2010 to 2019 net energy for load (NEL) declined by -0.33% (Schedule 2.3.1 Column 4), primarily due to terminated contracts in the Sales for Resale or Wholesale jurisdiction (Schedule 2.3.1 Column 2). Historically, the 2019 Sales for Resale value has fallen 583 GWh from its 2010 level. The level of Wholesale NEL over the ten-year forecast is projected to decline an additional 2,012 GWh from the 2019 level. This decline is offset by a projected increase in the much larger retail energy sector which is projected to grow 7.8% over the next decade.

During the 2010 to 2019 historical period the DEF summer net firm demand (Schedule 3.1 Column 10) increased from 8,929 MW to 9,260 MW, an average annual ten-year increase of 0.4% per year. Warm summer temperatures drove both Retail and Wholesale demand levels significantly higher than prior year (Columns 3 and 4). The -2.4% average ten-year decline in DEF wholesale load sector reflects the long-term reduction in Sales for Resale contracts. The projected total DEF summer net firm demand declines by an average annual -9.5 MW or -0.1% per year over the ten-year horizon due to continued projected declines in wholesale peak demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided to represent DEF's expectations for a Base Case as well as reasonable High and Low forecast scenarios for resource planning purposes. (Base-B, High-H and Low-L):

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class (B, H and L)
3.1	History and Forecast of Base Summer Peak Demand (MW) (B, H and L)
3.2	History and Forecast of Base Winter Peak Demand (MW) (B, H and L)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh) (B, H and L)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month (B, H and L)

DUKE ENERGY FLORIDA

SCHEDULE 2.1.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,625,558	2.496	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,641,179	2.496	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,713,013	2.495	18,508	1,488,159	12,437	11,718	165,936	70,617
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,040,257	2.485	20,775	1,626,117	12,776	12,198	178,036	68,514
FORECAST:								
2020	4,084,807	2.479	20,771	1,647,764	12,605	12,157	180,059	67,517
2021	4,143,110	2.478	20,954	1,671,957	12,533	12,247	182,170	67,228
2022	4,199,107	2.475	21,062	1,696,746	12,413	12,311	184,489	66,730
2023	4,253,915	2.470	21,223	1,722,233	12,323	12,381	186,886	66,246
2024	4,310,646	2.466	21,315	1,748,031	12,194	12,436	189,181	65,736
2025	4,365,966	2.461	21,624	1,774,062	12,189	12,610	191,393	65,885
2026	4,416,028	2.454	21,637	1,799,522	12,024	12,588	193,571	65,029
2027	4,467,149	2.448	21,894	1,824,816	11,998	12,646	195,729	64,608
2028	4,517,624	2.443	22,334	1,849,212	12,077	12,819	197,818	64,801
2029	4,567,233	2.439	22,604	1,872,584	12,071	12,872	199,843	64,410

DUKE ENERGY FLORIDA

SCHEDULE 2.1.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,625,558	2.496	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,641,179	2.496	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,713,013	2.495	18,508	1,488,159	12,437	11,718	165,936	70,617
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,040,257	2.485	20,775	1,626,117	12,776	12,198	178,036	68,514
FORECAST:								
2020	4,101,544	2.479	23,969	1,654,516	14,487	12,586	180,469	69,739
2021	4,177,878	2.478	24,340	1,685,988	14,437	12,749	183,021	69,660
2022	4,252,527	2.475	24,661	1,718,331	14,352	12,887	185,799	69,362
2023	4,326,593	2.470	25,026	1,751,657	14,287	13,032	188,671	69,074
2024	4,403,208	2.466	25,357	1,785,567	14,201	13,164	191,459	68,754
2025	4,478,985	2.461	25,837	1,819,986	14,196	13,411	194,180	69,066
2026	4,550,009	2.454	26,111	1,854,119	14,083	13,469	196,884	68,410
2027	4,622,629	2.448	26,599	1,888,329	14,086	13,606	199,582	68,172
2028	4,695,106	2.443	27,260	1,921,861	14,184	13,856	202,226	68,518
2029	4,767,214	2.439	27,767	1,954,577	14,206	13,995	204,818	68,329

DUKE ENERGY FLORIDA

SCHEDULE 2.1.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,625,558	2.496	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,641,179	2.496	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,713,013	2.495	18,508	1,488,159	12,437	11,718	165,936	70,617
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,040,257	2.485	20,775	1,626,117	12,776	12,198	178,036	68,514
FORECAST:								
2020	4,068,085	2.479	18,740	1,641,018	11,420	11,624	179,650	64,704
2021	4,108,503	2.478	18,752	1,657,991	11,310	11,645	181,323	64,223
2022	4,146,147	2.475	18,712	1,675,346	11,169	11,641	183,191	63,545
2023	4,182,158	2.470	18,715	1,693,182	11,053	11,641	185,123	62,880
2024	4,219,638	2.466	18,674	1,711,126	10,913	11,631	186,942	62,220
2025	4,255,310	2.461	18,762	1,729,098	10,850	11,729	188,665	62,167
2026	4,285,397	2.454	18,652	1,746,291	10,681	11,647	190,341	61,191
2027	4,316,194	2.448	18,738	1,763,151	10,628	11,635	191,987	60,601
2028	4,346,033	2.443	18,981	1,778,974	10,670	11,726	193,556	60,581
2029	4,374,704	2.439	19,075	1,793,647	10,635	11,709	195,053	60,030

DUKE ENERGY FLORIDA

SCHEDULE 2.2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
		AVERAGE	AVERAGE KWh	RAILROADS	STREET & HIGHWAY	OTHER SALES TO PUBLIC	TOTAL SALES TO ULTIMATE
		NO. OF	CONSUMPTION	AND RAILWAYS	LIGHTING	AUTHORITIES	CONSUMERS
YEAR	GWh	CUSTOMERS	PER CUSTOMER	GWh	GWh	GWh	GWh
HISTORY:							
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,343	1,368,331	0	25	3,159	36,616
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
FORECAST:							
2020	3,224	2,002	1,610,381	0	24	3,222	39,397
2021	3,410	2,000	1,704,798	0	24	3,223	39,857
2022	3,599	2,000	1,799,406	0	23	3,233	40,228
2023	3,642	2,000	1,821,147	0	23	3,245	40,513
2024	3,672	2,000	1,835,899	0	23	3,257	40,704
2025	3,677	2,000	1,838,469	0	23	3,272	41,206
2026	3,656	2,000	1,828,095	0	23	3,284	41,188
2027	3,652	2,000	1,825,783	0	23	3,299	41,513
2028	3,661	2,000	1,830,546	0	22	3,316	42,152
2029	3,650	2,000	1,824,774	0	22	3,334	42,481

DUKE ENERGY FLORIDA

SCHEDULE 2.2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,343	1,368,331	0	25	3,159	36,616
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
FORECAST:							
2020	3,250	2,002	1,623,678	0	24	3,323	43,151
2021	3,444	2,000	1,722,135	0	24	3,334	43,891
2022	3,641	2,000	1,820,690	0	23	3,354	44,567
2023	3,693	2,000	1,846,332	0	23	3,376	45,151
2024	3,730	2,000	1,864,938	0	23	3,400	45,673
2025	3,742	2,000	1,871,222	0	23	3,424	46,437
2026	3,730	2,000	1,864,758	0	23	3,449	46,781
2027	3,732	2,000	1,866,195	0	23	3,475	47,436
2028	3,748	2,000	1,874,112	0	22	3,503	48,389
2029	3,744	2,000	1,872,139	0	22	3,533	49,061

DUKE ENERGY FLORIDA

SCHEDULE 2.2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
2013	3,206	2,343	1,368,331	0	25	3,159	36,616
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
FORECAST:							
2020	3,188	2,002	1,592,766	0	24	3,103	36,679
2021	3,366	2,000	1,683,241	0	24	3,094	36,881
2022	3,548	2,000	1,774,201	0	23	3,094	37,019
2023	3,585	2,000	1,792,416	0	23	3,095	37,060
2024	3,608	2,000	1,803,884	0	23	3,098	37,034
2025	3,606	2,000	1,803,115	0	23	3,101	37,221
2026	3,580	2,000	1,789,822	0	23	3,105	37,007
2027	3,569	2,000	1,784,554	0	23	3,109	37,074
2028	3,573	2,000	1,786,306	0	22	3,114	37,416
2029	3,556	2,000	1,777,902	0	22	3,121	37,483

DUKE ENERGY FLORIDA

SCHEDULE 2.3.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,759	1,682,197
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,324	2,756	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
FORECAST:					
2020	1,460	2,788	43,645	26,903	1,856,728
2021	1,379	2,703	43,939	27,100	1,883,227
2022	1,611	2,752	44,591	27,296	1,910,532
2023	1,265	2,757	44,536	27,488	1,938,607
2024	1,266	2,911	44,880	27,680	1,966,893
2025	898	2,617	44,721	27,867	1,995,322
2026	898	2,868	44,955	28,056	2,023,149
2027	898	2,857	45,268	28,245	2,050,789
2028	898	2,728	45,778	28,434	2,077,463
2029	898	2,745	46,124	28,622	2,103,049

DUKE ENERGY FLORIDA

SCHEDULE 2.3.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,759	1,682,197
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,324	2,756	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
FORECAST:					
2020	1,460	3,445	48,056	26,903	1,863,890
2021	1,379	3,418	48,688	27,103	1,898,112
2022	1,611	3,484	49,662	27,300	1,933,430
2023	1,265	3,518	49,934	27,492	1,969,820
2024	1,266	3,663	50,602	27,684	2,006,709
2025	898	3,461	50,796	27,872	2,044,037
2026	898	3,701	51,380	28,060	2,081,063
2027	898	3,719	52,052	28,249	2,118,160
2028	898	3,622	52,909	28,439	2,154,525
2029	898	3,682	53,640	28,627	2,190,023

DUKE ENERGY FLORIDA

SCHEDULE 2.3.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,759	1,682,197
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,324	2,756	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
FORECAST:					
2020	1,460	2,711	40,850	26,903	1,849,574
2021	1,379	2,642	40,902	27,100	1,868,414
2022	1,611	2,666	41,296	27,296	1,887,834
2023	1,265	2,659	40,983	27,488	1,907,793
2024	1,266	2,755	41,055	27,680	1,927,748
2025	898	2,523	40,642	27,867	1,947,629
2026	898	2,703	40,608	28,056	1,966,687
2027	898	2,676	40,647	28,245	1,985,383
2028	898	2,545	40,859	28,434	2,002,963
2029	898	2,556	40,937	28,622	2,019,322

DUKE ENERGY FLORIDA

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2010	10,242	1272	8,970	271	304	298	96	234	110	8,929
2011	9,972	934	9,038	227	317	329	97	256	110	8,636
2012	9,788	1080	8,708	262	328	358	98	280	124	8,337
2013	9,581	581	9,000	317	341	382	101	298	124	8,017
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1021	10,008	230	394	566	86	414	80	9,260
FORECAST:										
2020	10,798	950	9,849	325	400	584	91	403	80	8,915
2021	10,872	963	9,909	335	407	603	95	406	80	8,946
2022	10,962	963	10,000	335	414	619	99	408	80	9,007
2023	10,718	662	10,056	335	421	633	104	409	80	8,735
2024	10,777	662	10,116	335	428	647	108	410	80	8,769
2025	10,623	461	10,162	335	435	662	112	410	80	8,588
2026	10,673	461	10,212	335	442	676	116	411	80	8,612
2027	10,751	461	10,290	335	449	689	121	411	80	8,666
2028	10,869	461	10,408	335	456	702	125	412	80	8,759
2029	10,963	461	10,502	335	463	715	129	412	80	8,829

Historical Values (2010 - 2019):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) =Customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2019 - 2028):
Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2010	10,242	1,272	8,970	271	304	298	96	234	110	8,929
2011	9,972	934	9,038	227	317	329	97	256	110	8,636
2012	9,788	1,080	8,708	262	328	358	98	280	124	8,337
2013	9,581	581	9,000	317	341	382	101	298	124	8,017
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
FORECAST:										
2020	11,957	950	11,008	325	400	584	91	403	80	10,074
2021	12,111	963	11,148	335	407	603	95	406	80	10,185
2022	12,275	963	11,312	335	414	619	99	408	80	10,319
2023	12,106	662	11,444	335	421	633	104	409	80	10,123
2024	12,239	662	11,578	335	428	647	108	410	80	10,231
2025	12,167	461	11,706	335	435	662	112	410	80	10,132
2026	12,298	461	11,837	335	442	676	116	411	80	10,237
2027	12,459	461	11,998	335	449	689	121	411	80	10,374
2028	12,656	461	12,195	335	456	702	125	412	80	10,546
2029	12,840	461	12,379	335	463	715	129	412	80	10,706

Historical Values (2010 - 2019):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2019 - 2028):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2010	10,242	1,272	8,970	271	304	298	96	234	110	8,929
2011	9,972	934	9,038	227	317	329	97	256	110	8,636
2012	9,788	1,080	8,708	262	328	358	98	280	124	8,337
2013	9,581	581	9,000	317	341	382	101	298	124	8,017
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
FORECAST:										
2020	10,136	950	9,186	325	400	584	91	403	80	8,252
2021	10,156	963	9,194	335	407	603	95	406	80	8,230
2022	10,190	963	9,227	335	414	619	99	408	80	8,235
2023	9,890	662	9,228	335	421	633	104	409	80	7,907
2024	9,893	662	9,231	335	428	647	108	410	80	7,885
2025	9,681	461	9,220	335	435	662	112	410	80	7,647
2026	9,673	461	9,212	335	442	676	116	411	80	7,613
2027	9,692	461	9,231	335	449	689	121	411	80	7,607
2028	9,747	461	9,285	335	456	702	125	412	80	7,637
2029	9,780	461	9,319	335	463	715	129	412	80	7,646

Historical Values (2010 - 2019):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2019 - 2028):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2009/10	13,694	2,189	11,505	246	651	563	80	163	322	11,670
2010/11	11,343	1,625	9,718	271	661	628	94	180	221	9,288
2011/12	9,721	905	8,816	186	643	686	96	203	206	7,701
2012/13	9,109	831	8,278	287	652	747	97	220	213	6,893
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	681	845	113	240	170	7,421
2016/17	8,739	701	8,038	191	687	878	78	243	165	6,497
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	84	251	164	6,130
FORECAST:										
2019/20	11,873	1,385	10,487	243	727	965	87	251	195	9,406
2020/21	11,350	713	10,637	299	741	983	91	252	196	8,789
2021/22	11,764	1,014	10,750	299	755	999	95	252	197	9,167
2022/23	11,554	713	10,841	299	769	1,014	99	253	198	8,922
2023/24	11,677	713	10,964	299	783	1,027	103	253	200	9,012
2024/25	11,475	512	10,962	299	797	1,043	108	253	199	8,777
2025/26	11,612	512	11,100	299	811	1,057	112	253	201	8,880
2026/27	11,705	512	11,193	299	825	1,070	116	253	202	8,941
2027/28	11,800	462	11,338	299	839	1,083	120	253	204	9,003
2028/29	11,867	462	11,404	299	853	1,095	125	253	204	9,038

Historical Values (2010 - 2019):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2020 - 2029):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2009/10	13,694	2,189	11,505	246	651	563	80	163	322	11,670
2010/11	11,343	1,625	9,718	271	661	628	94	180	221	9,288
2011/12	9,721	905	8,816	186	643	686	96	203	206	7,701
2012/13	9,109	831	8,278	287	652	747	97	220	213	6,893
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	681	845	113	240	170	7,421
2016/17	8,739	701	8,038	191	687	878	78	243	165	6,497
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	84	251	164	6,130
FORECAST:										
2019/20	12,675	1,385	11,289	243	727	965	87	251	195	10,208
2020/21	12,227	713	11,514	299	741	983	91	252	196	9,666
2021/22	12,707	1,014	11,693	299	755	999	95	252	197	10,110
2022/23	12,569	713	11,856	299	769	1,014	99	253	198	9,937
2023/24	12,764	713	12,051	299	783	1,027	103	253	200	10,099
2024/25	12,661	512	12,149	299	797	1,043	108	253	199	9,963
2025/26	12,853	512	12,341	299	811	1,057	112	253	201	10,121
2026/27	13,026	512	12,514	299	825	1,070	116	253	202	10,262
2027/28	13,200	462	12,738	299	839	1,083	120	253	204	10,403
2028/29	13,349	462	12,886	299	853	1,095	125	253	204	10,520

Historical Values (2010 - 2019):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2020 - 2029):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2009/10	13,694	2,189	11,505	246	651	563	80	163	322	11,670
2010/11	11,343	1,625	9,718	271	661	628	94	180	221	9,288
2011/12	9,721	905	8,816	186	643	686	96	203	206	7,701
2012/13	9,109	831	8,278	287	652	747	97	220	213	6,893
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	681	845	113	240	170	7,421
2016/17	8,739	701	8,038	191	687	878	78	243	165	6,497
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	84	251	164	6,130
FORECAST:										
2019/20	10,072	1,385	8,687	243	727	965	87	251	195	7,605
2020/21	9,486	713	8,773	299	741	983	91	252	196	6,925
2021/22	9,839	1,014	8,825	299	755	999	95	252	197	7,242
2022/23	9,567	713	8,854	299	769	1,014	99	253	198	6,935
2023/24	9,618	713	8,905	299	783	1,027	103	253	200	6,953
2024/25	9,362	512	8,850	299	797	1,043	108	253	199	6,664
2025/26	9,437	512	8,924	299	811	1,057	112	253	201	6,705
2026/27	9,466	512	8,954	299	825	1,070	116	253	202	6,702
2027/28	9,485	462	9,023	299	839	1,083	120	253	204	6,688
2028/29	9,497	462	9,035	299	853	1,095	125	253	204	6,669

Historical Values (2010 - 2019):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2020 - 2029):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.3.1
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.1
2013	43,142	772	734	864	36,616	1,488	2,668	40,772	53.0
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,324	2,755	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
FORECAST:									
2020	46,219	1,027	951	596	39,397	1,460	2,788	43,645	52.8
2021	46,539	1,048	957	595	39,857	1,379	2,703	43,939	56.1
2022	47,217	1,069	961	595	40,228	1,611	2,752	44,591	55.5
2023	47,185	1,090	965	595	40,513	1,265	2,757	44,536	57.0
2024	47,554	1,110	968	596	40,704	1,266	2,911	44,880	56.7
2025	47,417	1,129	972	595	41,206	898	2,617	44,721	58.2
2026	47,673	1,147	976	595	41,188	898	2,868	44,955	57.8
2027	48,007	1,165	979	595	41,513	898	2,857	45,268	57.8
2028	48,539	1,182	983	596	42,152	898	2,728	45,778	57.9
2029	48,903	1,199	986	595	42,481	898	2,745	46,124	58.3

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.2
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
HIGH CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.1
2013	43,142	772	734	864	36,616	1,488	2,668	40,772	53.0
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,324	2,755	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
FORECAST:									
2020	50,630	1,027	951	596	43,151	1,460	3,445	48,056	53.6
2021	51,289	1,048	957	595	43,891	1,379	3,418	48,688	57.5
2022	52,288	1,069	961	595	44,567	1,611	3,484	49,662	56.1
2023	52,560	1,069	961	595	45,151	1,611	3,172	49,934	57.4
2024	53,252	1,090	965	595	45,673	1,265	3,664	50,602	57.2
2025	53,492	1,129	972	595	46,437	898	3,461	50,796	58.2
2026	54,098	1,147	976	595	46,781	898	3,701	51,380	57.9
2027	54,792	1,165	979	595	47,436	898	3,719	52,052	57.9
2028	55,670	1,182	983	596	48,389	898	3,622	52,909	57.9
2029	56,420	1,199	986	595	49,061	898	3,682	53,640	58.2

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
LOW CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	1,768	3,065	41,214	52.1
2013	43,142	772	734	864	36,616	1,488	2,668	40,772	53.0
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,324	2,755	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
FORECAST:									
2020	43,424	1,027	951	596	36,679	1,460	2,711	40,850	61.1
2021	43,503	1,048	957	595	36,881	1,379	2,642	40,902	67.4
2022	43,921	1,069	961	595	37,019	1,611	2,666	41,296	65.1
2023	43,633	1,090	965	595	37,060	1,265	2,659	40,983	67.5
2024	43,729	1,110	968	596	37,034	1,266	2,755	41,055	67.2
2025	43,338	1,129	972	595	37,221	898	2,523	40,642	69.6
2026	43,326	1,147	976	595	37,007	898	2,703	40,608	69.1
2027	43,386	1,165	979	595	37,074	898	2,676	40,647	69.2
2028	43,620	1,182	983	596	37,416	898	2,545	40,859	69.6
2029	43,716	1,199	986	595	37,483	898	2,556	40,937	70.1

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 4.1
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2019		2020		2021	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,248	3,239	10,577	3,110	10,035	3,154
FEBRUARY	6,784	2,775	8,416	2,843	7,830	2,805
MARCH	6,632	3,037	7,971	3,048	7,375	3,086
APRIL	7,521	3,342	7,832	3,227	7,773	3,251
MAY	9,175	4,147	8,829	3,945	8,757	3,952
JUNE	9,970	4,526	9,498	4,270	9,630	4,315
JULY	9,585	4,594	9,624	4,603	9,690	4,608
AUGUST	9,190	4,658	9,731	4,520	9,783	4,527
SEPTEMBER	9,273	4,400	9,325	4,245	9,392	4,270
OCTOBER	8,393	4,131	8,565	3,682	8,735	3,718
NOVEMBER	6,918	2,994	7,020	2,989	7,174	3,043
DECEMBER	5,895	2,958	9,471	3,165	9,108	3,210
TOTAL		44,801		43,645		43,939

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.

DUKE ENERGY FLORIDA

SCHEDULE 4.2
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2019		2020		2021	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,248	3,239	11,404	3,793	10,926	3,862
FEBRUARY	6,784	2,775	9,189	3,385	8,656	3,379
MARCH	6,632	3,037	8,642	3,574	8,097	3,636
APRIL	7,521	3,342	8,466	3,530	8,461	3,578
MAY	9,175	4,147	9,495	4,149	9,486	4,184
JUNE	9,970	4,526	10,168	4,467	10,369	4,543
JULY	9,585	4,594	10,272	4,768	10,397	4,804
AUGUST	9,190	4,658	10,382	4,671	10,503	4,708
SEPTEMBER	9,273	4,400	9,980	4,409	10,111	4,463
OCTOBER	8,393	4,131	9,241	3,959	9,463	4,022
NOVEMBER	6,918	2,994	7,801	3,439	8,020	3,519
DECEMBER	5,895	2,958	10,320	3,913	10,018	3,990
TOTAL		44,801		48,056		48,688

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.

DUKE ENERGY FLORIDA

SCHEDULE 4.3
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	A C T U A L		F O R E C A S T		F O R E C A S T	
	2019		2020		2021	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,248	3,239	8,776	2,931	8,172	2,951
FEBRUARY	6,784	2,775	6,910	2,665	6,278	2,617
MARCH	6,632	3,037	6,618	2,791	5,979	2,807
APRIL	7,521	3,342	7,236	2,973	7,137	2,978
MAY	9,175	4,147	8,208	3,704	8,091	3,689
JUNE	9,970	4,526	8,843	3,993	8,917	4,015
JULY	9,585	4,594	8,977	4,397	8,984	4,379
AUGUST	9,190	4,658	9,068	4,262	9,067	4,245
SEPTEMBER	9,273	4,400	8,690	3,995	8,718	3,999
OCTOBER	8,393	4,131	7,949	3,435	8,084	3,452
NOVEMBER	6,918	2,994	6,298	2,788	6,417	2,826
DECEMBER	5,895	2,958	7,845	2,917	7,443	2,945
TOTAL		44,801		40,850		40,902

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. Although DEF's fuel mix continues to rely on an increasing amount of natural gas to meet its generation needs, DEF continues to maintain alternate fuel supplies including long term operation of some coal fired facilities, adequate supplies of oil for dual fuel back up and increasing amounts of renewable generation particularly from solar generation. Projections shown in Schedules 5 and 6 reflect the Base Load and Energy Forecasts.

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	3,746	1,976	1,735	1,782	1,701	1,455	1,329	1,523	1,525	1,583	1,796	1,803
(3)	RESIDUAL	TOTAL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	198	121	66	73	53	41	133	110	133	169	242	193
(9)		STEAM	1,000 BBL	55	42	19	19	19	24	24	26	28	26	20	24
(10)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	143	79	46	54	34	17	109	84	105	143	222	169
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	222,083	246,124	233,860	235,307	235,624	232,804	244,581	241,656	243,558	250,990	251,574	251,051
(14)		STEAM	1,000 MCF	29,207	25,020	8,141	9,551	10,207	10,041	10,365	11,757	12,232	12,539	13,610	12,703
(15)		CC	1,000 MCF	184,419	210,736	220,983	221,465	220,928	218,842	227,711	224,566	224,929	227,109	226,859	227,467
(16)		CT	1,000 MCF	8,456	10,369	4,736	4,291	4,489	3,921	6,506	5,334	6,398	11,342	11,105	10,881
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	N/A	N/A	6,766	1,044	0	0	0	0	0	0	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	N/A	N/A	12,025	14,614	14,055	16,965	12,096	12,717	11,799	2,470	0	0
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	N/A	N/A	0	0	0	0	0	0	0	0	0	0

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	2,244	1,062	1,170	1,425	1,367	1,648	1,176	1,234	1,146	249	39	34
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	8,422	4,322	3,661	3,763	3,522	2,985	2,735	2,963	2,952	3,099	3,551	3,540
(4)	RESIDUAL	TOTAL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	90	30	17	20	13	6	41	32	39	55	86	65
(10)		STEAM	GWh	30	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	61	30	17	20	13	6	41	32	39	55	86	65
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	28,687	35,092	34,078	34,189	34,109	33,770	35,311	34,780	34,955	35,684	35,587	35,671
(15)		STEAM	GWh	2,714	2,278	627	735	782	767	801	912	957	984	1,073	995
(16)		CC	GWh	25,360	31,911	32,997	33,028	32,875	32,603	33,910	33,363	33,403	33,686	33,588	33,733
(17)		CT	GWh	612	903	454	425	452	400	600	505	595	1,014	926	942
(18)	OTHER 2/														
	QF PURCHASES		GWh	1,826	1,803	1,994	1,999	2,003	2,003	822	497	2	2	2	2
	RENEWABLES OTHER		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES MSW		GWh	845	670	946	941	956	956	956	949	949	949	952	949
	RENEWABLES BIOMASS		GWh	399	15	0	0	0	0	0	0	0	0	0	0
	RENEWABLES SOLAR		GWh	26	222	835	1,460	2,620	3,167	3,840	4,266	4,912	5,231	5,562	5,862
	IMPORT FROM OUT OF STATE		GWh	1,685	1,290	943	142	0	0	0	0	0	0	0	0
	EXPORT TO OUT OF STATE		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	44,224	44,505	43,645	43,939	44,591	44,536	44,880	44,721	44,955	45,268	45,778	46,124

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	ANNUAL FIRM INTERCHANGE 1/		%	5.1%	2.4%	2.7%	3.2%	3.1%	3.7%	2.6%	2.8%	2.5%	0.5%	0.1%	0.1%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	19.0%	9.7%	8.4%	8.6%	7.9%	6.7%	6.1%	6.6%	6.6%	6.8%	7.8%	7.7%
(4)	RESIDUAL	TOTAL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
(10)		STEAM	%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	64.9%	78.8%	78.1%	77.8%	76.5%	75.8%	78.7%	77.8%	77.8%	78.8%	77.7%	77.3%
(15)		STEAM	%	6.1%	5.1%	1.4%	1.7%	1.8%	1.7%	1.8%	2.0%	2.1%	2.2%	2.3%	2.2%
(16)		CC	%	57.3%	71.7%	75.6%	75.2%	73.7%	73.2%	75.6%	74.6%	74.3%	74.4%	73.4%	73.1%
(17)		CT	%	1.4%	2.0%	1.0%	1.0%	1.0%	0.9%	1.3%	1.1%	1.3%	2.2%	2.0%	2.0%
(18)	OTHER 2/														
	QF PURCHASES		%	4.1%	4.1%	4.6%	4.5%	4.5%	4.5%	1.8%	1.1%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES OTHER		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES MSW		%	1.9%	1.5%	2.2%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
	RENEWABLES BIOMASS		%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES SOLAR		%	0.1%	0.5%	1.9%	3.3%	5.9%	7.1%	8.6%	9.5%	10.9%	11.6%	12.1%	12.7%
	IMPORT FROM OUT OF STATE		%	3.8%	2.9%	2.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

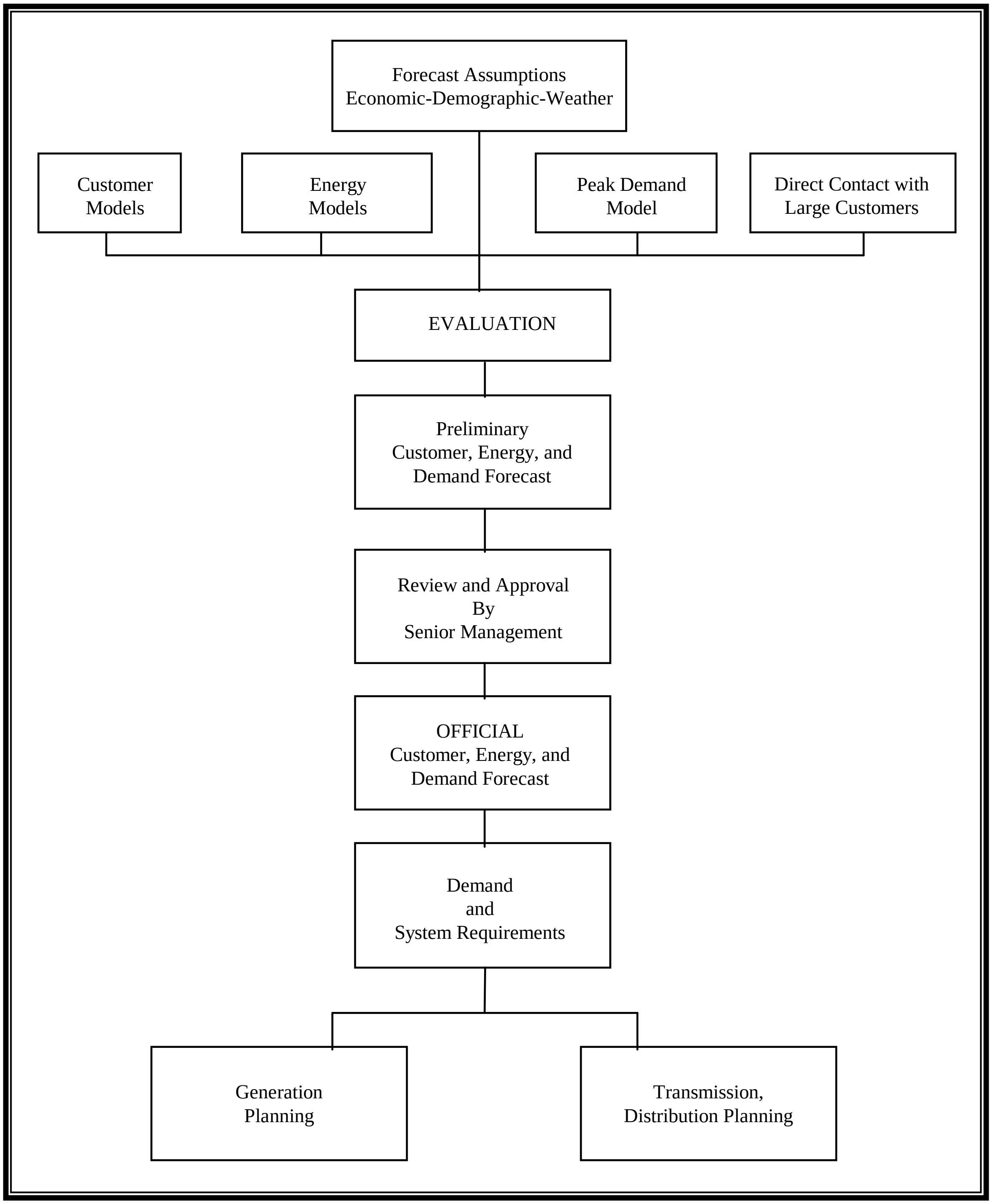
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of several external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 30-year average of conditions at the St Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 30-year average of calendar and billing cycle weighted monthly heating and cooling degree-days (HDD and CDD). The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the 30-year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day (DD) values begin to accumulate. Seasonal and monthly peak demand projections are based on a 30-year historical average of system-weighted degree days using the "Itron Rank-Sort Normal" approach which takes annual weather extremes into account as well as the date and hour of occurrence.

2. DEF customer forecast is based upon historical population estimates and produced by the BEBR at the University of Florida (as published in "Florida Population Studies", Bulletin No. 183 April 2019) and provides the basis for the population forecast used in the development of the DEF customer forecast. National and Florida economic projections produced by Moody's Analytics in their July 2019 forecast, along with EIA 2019 surveys of residential appliance saturation and average appliance efficiency levels provided the basis for development of the DEF energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Three major customers accounted for 24% of the industrial class MWh sales in 2019, significantly less than 2018. These energy intensive "crop nutrient" producers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, international trade pacts and U.S. environmental regulations. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations.

Going forward, global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. The DEF forecast calls for a rebound in electric consumption from this sector as a major producer restructures its supply chain. The U.S. farm sector was hit hard by retaliatory sanctions from China which imports U.S. farm products. The forecast does account for one customer's intention to open a new mine in phases between the years 2020 and 2022. Any increase in self-service generation will act to reduce energy requirements from DEF. An upside risk to this projection lies in the price of energy, especially low natural gas price, which is a major cost in mining and producing phosphoric fertilizers. Trade issues are expected to stabilize in 2020 and demand for farm products should improve, as will the demand for crop nutrients.

4. DEF supplies load and energy service to wholesale customers on a "full" and "partial" requirement basis. Full requirements (FR) customers demand and energy are assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Chattahoochee, Mt. Dora and Williston. Partial requirements (PR) customers load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Reedy Creek Improvement District (RCID) and Seminole Electric Cooperative, Inc. (SECI). Many contracts are projected to "term out" in various years in this projection.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently FPSC approved DSM goals as stated in Docket No. 20190018-EG.

7. This forecast reflects impacts from both Plug-in Hybrid Electric Vehicle (PHEV) and behind the meter (customer owned) Photo Voltaic (PV) units on energy and peak demand. PHEV customer penetration levels, which are expected to be a small share of the total DEF service area vehicle stock over the planning horizon, incorporates an EPRI Model view that includes gasoline price expectations. DEF customer PV penetration levels are expected to continue to grow over the

planning horizon and the forecast incorporates a view on equipment and electric price impacts on customer use.

8. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. DEF will supply the supplemental load of self-service cogeneration customers. While DEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place. FR customers are typically assumed to renew their contracts with DEF except those who have termination provisions and have given their notice to terminate.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2019 as the nation's economy set a new record for length of business cycle expansion continuing a pace of steady if modest growth. Most economic indicators pointed to significant year-over-year improvements in the near term. These included strong employment growth and declining unemployment, minimal home foreclosures, much improved home construction levels and consumer confidence. Nationally, energy prices and interest rates are extremely low and relatively stable. Consumers were spending (and borrowing) again. More recently there are signs of marginal improvement in median household incomes (after inflation) and improvement in the rate of homeownership. As the reported rate of national unemployment is now at or below 4%, the tightening of the labor supply typically leads to wage increases. Increased consumer confidence, along with reasonable mortgage rates has revived the desire to own homes but home price affordability measures now limit many from entering the single-family market. The nation's manufacturing sector has slowed considerably in 2019 as it had to navigate through an uncertain trade war which increased prices on imported products and exported products due to retaliatory tariffs. The U.S. service sector is also riding a wave of favorable conditions. Stable interest rates and energy prices have invigorated the American consumer and are now being reflected in higher consumer sentiment surveys. This forecast does consider the waning effects from the 2017 Tax Cuts and Jobs Act passed in 2018. Stimulus supplied by this policy helped support growth in national and state economies in 2018 but only marginally in 2019.

The Florida economy continues to expand at a good clip, the level of consumer sentiment, as measured by the University of Florida-BEBR, has remained close to its April 2019 peak. Newly released 2019 estimates of Florida population show an increase in resident population of 368,021 from 2018's level, breaking the >1,000 new residents per day threshold. This creates a healthy demand for housing and services throughout the State. Duke Energy load forecasts have been expecting Florida to benefit from an on-rush of retirees for several years. After some delay created by the financial crisis, one can safely say this trend has begun. This impact is expected to peak in 2025 but continue through most of the 2020s.

The Florida unemployment rate dropped to 3.0% in December 2019, down from 3.3% a year earlier. The State's employment picture has continued to be strong, adding 212,000 jobs over the year, topped only by California and Texas.

Throughout the ten-year forecast horizon, risks and uncertainties are always recognized and handled on a "highest probability of outcome" basis. General rules of economic theory, namely, supply and demand equilibrium are maintained in the long run. This notion is applied to energy/commodity prices, currency levels, the housing market, wage rates, birth rates, inflation and interest rates. Uncertainty surrounding specific weather anomalies (hurricanes or earthquakes), international crises, such as wars or terrorist acts, are not explicitly designed into this projection. Thus, any situations of this variety will result in a deviation from this forecast.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer-class specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, demand response, interruptible service and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody’s Analytics and the University of Florida's BEBR. Internal company forecasts are used for projections of electricity price, weather conditions, the length of the billing month and rates of customer owned renewable and electric vehicle adoption. The incorporation of residential and commercial “end-use” energy has been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company’s Market Research department and the Energy Information Agency (EIA), along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an easier explanation of usage levels and changes in weather-sensitivity over time. The “bundling” of 19 residential appliances into “heating”, “cooling” and “other” end uses form the basis of equipment-oriented drivers that interact with typical exogenous factors such as real median household income, average household size, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with county level population projections for counties in which DEF serves residential customers are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. As in the residential sector, these variables are interacted with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation
- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the EIA's Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment interacted with the Florida industrial production index, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF Large Account Management employees provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon. These Florida mining companies compete globally into a global market where farming conditions dictate the need for “crop nutrients”. The projection of industrial accounts is not expected to decline as rapidly as it has for years. The pace of “off-shoring” manufacturing jobs is expected to decline from past levels. Secondly, the rapid increase in Florida population should recalibrate Florida’s competitiveness in “location analysis” studies performed by industry when determining site selection for new operations.

Street Lighting

Electricity sales to the street and highway lighting class have now declined for several years. A continued decline is expected as improvements in lighting efficiency are projected. The number of accounts, which has dropped by more than one-third since 1995 due to most transferring to public authority ownership, is expected to decline further before leveling off in the intermediate term. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised of federal, state and local government operated services, is also projected to grow within the DEF's service area. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e. public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days and the sales month billing days, results in a significant level of explained variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use throughout the year. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or sales for resale, customer of DEF that contracts for both seasonal and stratified loads over the forecast horizon. The municipal sales for resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Three customers in this class, Chattahoochee, Mt. Dora, and Williston, are municipalities whose full energy requirements are supplied by DEF. Energy projections for full requirement customers grow at a rate that approximates their historical trend with additional information coming from the respective city officials. DEF serves partial requirement service (PR) to municipalities such as RCID. In each case, these customers contract with DEF for a specific level and type of stratified capacity needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load and expected fuel prices. Electric energy growth and competitive market prices will dictate the amount of wholesale demand and energy throughout the forecast horizon.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF's coincident system peak is separated into five major components. These components consist of total retail load, interruptible and curtailable tariff non-firm load, conservation and demand response program capability, wholesale demand, and company use demand.

Total retail load refers to projections of DEF retail monthly net peak demand before any activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak and the amounts of Base-Heating-Cooling load estimated by the monthly Itron models without the impacts of year-to-year variation in utility-sponsored DR programs. Monthly peaks are projected using the Itron SAE generated use patterns for both weather sensitive (cooling & heating) appliances and base load appliances calculated by class in the energy models. Daily and hourly models of applying DEF class-of-business load research survey data lead to class and total retail hourly load profiles when a 30-year normal weather template replaces actual weather. The projections of retail peak are the result of a monthly model driven by the summation of class base, heating and cooling energy interpolated 30-year normal weather pattern-driven load profile. The projection for the months of January (winter) and August (summer) are typically when the seasonal peaks occur. Energy conservation and direct load control estimates consistent with DEF's DSM goals that have been established by the FPSC are applied to the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of firm retail monthly peak demand figures. The Interruptible and Curtailable service (IS and CS) tariff load projection is developed from historic monthly trends, as well as the incorporation of specific projected information obtained from DEF's large industrial accounts on these tariffs by account executives. Developing this piece of the demand forecast allows for appropriate firm retail demand results in the total retail coincident peak demand projection.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of seasonal demands. The Full Requirement municipal demand forecast is estimated for individual cities using historically trended growth rates adjusted for current economic conditions.

DEF "company use" at the time of system peak is estimated using load research metering studies similar to potential firm retail. It is assumed to remain stable over the forecast horizon as it has historically.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

HIGH & LOW SCENARIOS

DEF has developed high and low scenarios around the base case energy sales and peak demand projections. The overall results reflect a one standard deviation probability of outcome, or 67% of all possible outcomes between the high case and low case. Of course, the base case represents the 50/50 probability of all expected outcomes.

Both scenarios incorporate historical variation in weather and economic conditions as well as service area population and household growth. First, a calculation of thirty years of historical variation for economic driver variables selected in the base case energy sales models. High & low case series were developed by determining the one standard deviation level of outcome - both high and low - around each respective base case economic variable for each class. Similarly, high and low weather variables were determined for the energy and peak weather variables (HDDs, CDDs, and monthly peak DDs) using actual 30-year weather conditions. Each weather variable used in the modeling process is ranked monthly from "high-to-low" degree days. The high (hottest) one-third of each variable is averaged and becomes a normal "High Case" weather condition. Similarly, the mildest one-third of each weather variable's 30 observations are averaged and become the normal "Low Case" weather condition.

This procedure captures the most influential variables around energy sales and peak demand by estimating high and low cases for economics and weather conditions.

CONSERVATION

On November 26, 2019, the FPSC issued Order No. PSC-2019-00509-FOF which established demand side management goals for the FEECA utilities for 2020-2024 based on the goals approved in the 2014 Goals setting proceeding (Order PSC-14-0696-FOF-EU). The residential and commercial goals from the 2014 Goals setting proceeding are depicted in Tables 2.1 and 2.2. DEF assumes the trends in these goals will be extended though the forecast period. As required by Florida Administrative Code, Rule 25-17.0021, DEF filed a Program Plan designed to meet these Commission established goals on February 24, 2020. These programs will be subject to periodic monitoring and evaluation to ensure that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable.

RESIDENTIAL CONSERVATION PROGRAMS

TABLE 2.1

Residential DSM MW and GWH Savings

Year	Annual Summer	Cumulative Summer	Annual Winter	Cumulative Winter	Annual GWH's	Cumulative GWH's
2020	15.5	15.5	32.2	32.2	9.3	9.3
2021	13.7	29.2	27.8	60.0	6.2	15.5
2022	12.2	41.4	24.5	84.5	3.8	19.3
2023	11.3	52.7	22.3	106.8	2.2	21.5

The following provides an overview of the DEF's Residential DSM Programs effective as of December 31, 2019:

Home Energy Check – This is DEF's home energy audit program as required by Rule 25-17.003(3) (b). DEF offers a variety of options to customers for home energy audits including walk-through audits, phone assisted audits, and web enabled on-line audits. At the completion of the audit, DEF also provides kits that contain energy saving measures that may be easily installed by the customer.

Residential Incentive Program – This program provides incentives on a variety of cost-effective measures designed to provide energy savings. DEF expects to provide incentives to customers for the installation of approximately 90,000 energy saving measures over the ten-year FEECA goal period. These measures primarily include heating and cooling, duct repair, insulation, and energy efficient windows. The measures and incentive levels included in this program have been updated to reflect the impacts of new codes and standards.

Neighborhood Energy Saver – This program is designed to provide energy saving education and assistance to low income customers. This program targets neighborhoods that meet certain income eligibility requirements. DEF installs energy saving measures in approximately 4,500 homes and provides home energy reports to approximately 15,000 customers annually through this program. These home energy reports provide information about energy efficiency and remind customers about low cost energy saving measures.

Low Income Weatherization Assistance Program – DEF partners with local agencies to provide funding for energy efficiency and weatherization measures to low income customers through this program. DEF expects to provide assistance to approximately 500 customers annually through this program.

EnergyWise – EnergyWise is a voluntary residential demand response program that provides monthly bill credits to customers who allow DEF to reduce peak demand by controlling service to selected electric equipment through various devices and communication options installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Customers must have a minimum average monthly usage of 600 kwh's to be eligible to participate in this program.

COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

TABLE 2.2

Commercial/Industrial DSM MW and GWH Savings

Year	Annual Summer	Cumulative Summer	Annual Winter	Cumulative Winter	Annual GWH's	Cumulative GWH's
2020	8.2	8.2	5.2	5.2	5.9	5.9
2021	6.9	15.1	4.8	10.0	3.9	9.8
2022	6.0	21.1	4.7	14.7	2.4	12.2
2023	5.6	26.7	5.0	19.7	1.4	13.6
2024	5.0	31.7	4.6	24.3	0.8	14.4

The following provides a list of the Commercial programs that we have as of December 31, 2019 along with a brief overview of each program:

Business Energy Check – This is a commercial energy audit program that provides commercial customers with an analysis of their energy usage and information about energy-saving practices and cost-effective measures that they can implement at their facilities.

Better Business – This program provides incentives to commercial customers on a variety of cost-effective energy efficiency measures. These measures include chillers, cool roof, insulation, and DX systems.

Florida Custom Incentive – The objective of this program is to encourage customers to make capital investments for the installation of energy efficiency measures which reduce energy and peak demand. This program provides incentives for customized energy efficiency projects and measures that are cost effective and are not otherwise included in DEF's prescriptive commercial programs.

Interruptible Service – This program is available to non-residential customers with a minimum billing demand of 500 KW or more who are willing to have their power interrupted. DEF has remote control access to the switch providing power to the customer's equipment. Customers participating in the Interruptible Service program receive a monthly interruptible demand credit based on their billing demand and billing load factor.

Curtailable Service - This program is an indirect load control program that reduces DEF's energy demand at times of capacity shortage during peak or emergency conditions.

Standby Generation - This program is a demand control program that reduces DEF's demand based upon the control of the customer equipment. The program is a voluntary program available to all commercial and industrial customers who have on-site stand-by generation capacity of at least 50 kW and are willing to reduce their DEF demand when deemed necessary.

OTHER DSM PROGRAMS

The following provides an overview of other DSM programs:

Technology Development – This program is used to fund research and development of new energy efficiency and demand response opportunities. DEF will use this program to investigate new technologies and support the development of new energy efficiency and demand response programs.

Qualifying Facilities – This program analyzes, forecasts, facilitates, and administers the potential and actual power purchases from Qualifying Facilities (QFs) and the state jurisdictional QF or distributed generator interconnections. The program supports meetings with interested parties or potential QFs, including cogeneration and small power production facilities including renewables interested in providing renewable capacity or energy deliveries within our service territory. Project, interconnection, and avoided cost discussions with renewable and combined heat and power developers who are also exploring distributed generation options continue to remain steady. Most of the interest is coming from companies utilizing solar photovoltaic technology as the price of photovoltaic panels has decreased over time. The cost of this technology continues to decrease, and subsidies remain in place. This increase in solar activity is evident in the number of interconnection requests which now represent over 5,500 MW of solar PV projects representing 80 active projects. As the technologies advance and the market evolves, the Company's policies will continue to be refined and compliant.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2019, DEF had a summer total capacity resource of 11,858 MW (see Table 3.1). This capacity resource includes fossil steam generators (2,425 MW), combined cycle plants (5,266 MW), combustion turbines (2,092 MW), solar power plants (119 MW), utility purchased power (424 MW), independent power purchases (1,120 MW), and non-utility purchased power (412 MW). Table 3.2 presents DEF's firm capacity contracts with Renewable and Cogeneration Facilities.

Demand-Side Programs

DEF will file Programs designed to meet the demand side management goals established by the Commission in Order PSC-2019-00509-FOF on February 24, 2020. Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. Demand forecasts shown in these schedules are based on Schedules 3.1.1 and 3.2.1, the base summer and winter forecasts. DEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with DEF. In its planning process, DEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of 1,403 MW of Solar PV generation with an expected equivalent summer firm capacity contribution of approximately 800 MW and 452 MW of new natural gas fired generation consisting of two planned combustion turbine units, one added in year 2027 and another in year 2029, at undesignated sites as well as the incorporation of the full firm capacity of the Osprey Energy Center. DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan. In this plan, DEF has assigned this DEF owned solar PV generation an equivalent summer capacity value equal to 57% of the nameplate capacity of the planned installations. This assignment assumes that the projects developed over the period of this plan will be single-axis tracking technology. We foresee that as more solar is added, the net-load peak hour will start to shift to later hours, and the solar contribution to firm capacity might decline. DEF plans to evaluate this assignment over time and may revise this value in future Site Plans based on changes in project designs and the data received from actual operation of these facilities once they are installed.

On June 19, 2019, EPA issued the Affordable Clean Energy (ACE) Rule to replace the 2015 Clean Power Plan. States now have three years to develop plans and two additional years to achieve compliance. It is anticipated that there may be delays to the schedule due to litigation. DEF is currently evaluating potential requirements for ACE Rule compliance but does not expect that these will result in material impacts to unit operations or capacity. Additional details regarding DEF's compliance strategies in response to the ACE rule are provided in DEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 190007-EI.

Although there continues to be significant uncertainty about the specific form of regulation, DEF continues to expect that more stringent CO_2 emissions limitations in one form or another will be part of the regulatory future and has incorporated a CO_2 emission price forecast as a placeholder for the impacts of such regulation.

DEF continues to modernize its generation resources with the retirement and projected retirements of several of the older units in the fleet, particularly combustion turbines at Avon Park, Bayboro, Debary

P2 - P6, Bartow P1 & P3, and University of Florida. Peakers at Higgins were retired at the end of 2019. Continued operations of the peaking units at Avon Park are planned until later in the year 2020 while Bayboro is planned through the year 2025. The Debary P2 - P6, Bartow P1 & P3, and University of Florida are planned to retire in 2027. There are many factors which may impact these retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2020 through 2029. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan. DEF has examined the high and low load scenarios presented in Schedules 3.1 and 3.2. As discussed in Chapter 2, these scenarios were developed to present and test a range of likely outcomes in peak load and energy demand. DEF found that the Base Expansion Plan was robust under the range of conditions examined. Current planned capacity is sufficient to meet the demand including reserve margin in these cases through 2023 allowing DEF sufficient time to plan additional generation capacity either through power purchase or new generation construction as needed if higher than baseline conditions emerge. If lower than baseline conditions emerge, DEF can defer future generation alternatives.

Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with DEF Bulk Electric System (BES) are shown in Schedule 10.

TABLE 3.1

DUKE ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2019

PLANTS	SUMMER NET DEPENDABLE CAPABILITY (MW)
Fossil Steam	2,425
Combined Cycle	5,266
Combustion Turbine	2092
Solar	119
Total Net Dependable Generating Capability	**9,902**
Dependable Purchased Power	1,956
Firm Qualifying Facility Contracts (412 MW)	
Investor Owned Utilities (424 MW)	
Independent Power Producers (1,120 MW)	
TOTAL DEPENDABLE CAPACITY RESOURCES	**11,858**

TABLE 3.2

**DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS**

AS OF DECEMBER 31, 2019

Facility Name	Firm Capacity (MW)
Mulberry	115
Orange Cogen (CFR-Biogen)	104
Orlando Cogen	115
Pasco County Resource Recovery	23
Pinellas County Resource Recovery 1	40
Pinellas County Resource Recovery 2	14.8
TOTAL	**411.8**

DUKE ENERGY FLORIDA

SCHEDULE 7.1
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2020	9,978	1,878	0	78	11,934	8,915	3,019	34%	0	3,019	34%
2021	10,021	1,454	0	78	11,553	8,946	2,607	29%	0	2,607	29%
2022	10,222	1,454	0	78	11,754	9,007	2,747	31%	0	2,747	31%
2023	10,305	1,454	0	78	11,837	8,735	3,102	36%	0	3,102	36%
2024	10,724	859	0	78	11,661	8,769	2,892	33%	0	2,892	33%
2025	10,721	744	0	78	11,543	8,588	2,955	34%	0	2,955	34%
2026	10,632	640	0	78	11,350	8,612	2,738	32%	0	2,738	32%
2027	10,566	0	0	78	10,644	8,666	1,978	23%	0	1,978	23%
2028	10,561	0	0	78	10,639	8,759	1,880	21%	0	1,880	21%
2029	10,826	0	0	78	10,903	8,829	2,074	23%	0	2,074	23%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 7.2
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2019/20	10,894	1,961	0	78	12,933	9,406	3,528	38%	0	3,528	38%
2020/21	10,850	1,961	0	78	12,889	8,789	4,101	47%	0	4,101	47%
2021/22	10,850	1,537	0	78	12,465	9,167	3,298	36%	0	3,298	36%
2022/23	10,850	1,537	0	78	12,465	8,922	3,543	40%	0	3,543	40%
2023/24	10,850	1,422	0	78	12,350	9,012	3,339	37%	0	3,339	37%
2024/25	11,205	785	0	78	12,068	8,777	3,291	38%	0	3,291	38%
2025/26	10,967	681	0	78	11,726	8,880	2,846	32%	0	2,846	32%
2026/27	10,967	681	0	78	11,726	8,941	2,785	31%	0	2,785	31%
2027/28	10,732	0	0	78	10,809	9,003	1,806	20%	0	1,806	20%
2028/29	10,732	0	0	78	10,809	9,038	1,771	20%	0	1,771	20%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2020 THROUGH DECEMBER 31, 2029

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
												FIRM			
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
COLUMBIA	1	COLUMBIA	PV	SO				08/2019	03/2020		74,900	43	0	P	(1)
DEBARY	1	VOLUSIA	PV	SO				07/2019	05/2020		74,500	34	0	P	(1)
TWIN RIVERS	1	HAMILTON	PV	SO				04/2020	12/2020		74,900	43	0	P	(1)
SANTA FE	1	COLUMBIA	PV	SO				04/2020	12/2020		74,900	43	0	P	(1)
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK			10/2020		(24)	(25)	RT	(1)
AVON PARK	P2	HIGHLANDS	GT	DFO		TK				10/2020		(24)	(25)	RT	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2021	12/2021		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2021	12/2021		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2021	12/2021		56,000	32	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(1)			(2)
UNKNOWN	1	UNKNOWN	PV	SO				05/2021	01/2022		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				05/2021	01/2022		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(1)			(2)
UNKNOWN	1	UNKNOWN	PV	SO				04/2023	05/2023		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2023	05/2023		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(2)			(2)
OSPREY CC	1	POLK	CC	NG	DFO	PL	TK		05/2024			337	355	P	(3)
UNKNOWN	1	UNKNOWN	PV	SO				04/2024	05/2024		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2024	05/2024		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(3)			(2)
UNKNOWN	1	UNKNOWN	PV	SO				04/2025	12/2025		74,900	43	0	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2025	12/2025		74,900	43	0	P	(1)
BAYBORO	P1 - P4	PINELLAS	GT	DFO		WA				12/2025		(171)	(238)		
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(3)			(2)
UNKNOWN	1	UNKNOWN	PV	SO				04/2026	12/2026		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(3)			(2)
DEBARY	P2 - P6	VOLUSIA	GT	DFO		TK				06/2027		(249)	(324)		
BARTOW	P1, P3	PINELLAS	GT	DFO		WA				06/2027		(82)	(105)		
UNKNOWN	P1	UNKNOWN	GT	NG	DFO	PL	TK	01/2025	06/2027		229,400	226	240	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2027	12/2027		74,900	43	0	P	(1)
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	DFO		WA				11/2027		(44)	(46)		
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
UNKNOWN	1	UNKNOWN	PV	SO				04/2028	12/2028		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
UNKNOWN	P2	UNKNOWN	GT	NG	DFO	PL	TK	01/2025	06/2029		229,400	226	240	P	(1)
UNKNOWN	1	UNKNOWN	PV	SO				04/2027	12/2029		74,900	43	0	P	(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)

a. See page v. for Code Legend of Future Generating Unit Status.
b. NOTES
(1) Planned, Prospective, or Committed project.
(2) Solar capacity degrades by 0.5% every year
(3) Osprey CC Acquisition total capacity is available once Transmission Upgrades are in service, total Summer capacity goes up to 582MW and total Winter capacity goes up to 600MW

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**Columbia**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		8/2019	
	b. Commercial in-service date:		3/2020	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~31 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/kWh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):		Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh):	($2020)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**DeBary**	
(2)	Capacity			
	a. Nameplate (MWac):		74.5	
	b. Summer Firm (MWac):		33.5	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2019	
	b. Commercial in-service date:		5/2020	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~300-400 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~24 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/kWh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):		Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh):	($2020)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**Twin Rivers**	
(2)	Capacity		
	a. Nameplate (MWac):	74.9	
	b. Summer Firm (MWac):	42.7	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2020	
	b. Commercial in-service date:	12/2020	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~450-550 ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~27 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/kW):	Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac): ($2020)		
	d. AFUDC Amount ($/kW):		
	e. Escalation ($/kW):		
	f. Fixed O&M ($/kWdc-yr): ($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh): ($2020)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**Santa Fe**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2020	
	b. Commercial in-service date:		12/2020	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-650 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):		Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh):	($2020)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2021	
	b. Commercial in-service date:		12/2021	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):		Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh):	($2020)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2021		
	b. Commercial in-service date:	12/2021	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):		Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)		Less than $8/Kw	
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	56.0	
	b. Summer Firm (MWac):	31.9	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2021	
	b. Commercial in-service date:	12/2021	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~450-550 ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~29 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/kW):	Less than $1,650/Kw	
	c. Direct Construction Cost ($/kWac): ($2020)		
	d. AFUDC Amount ($/kW):		
	e. Escalation ($/kW):		
	f. Fixed O&M ($/kWdc-yr): ($2020)	Less than $8/Kw	
	g. Variable O&M ($/MWh): ($2020)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	74.9	
	b. Summer Firm (MWac):	42.7	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	5/2021	
	b. Commercial in-service date:	01/2022	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):		N/A %
	b. Forced Outage Factor (FOF):		N/A %
	c. Equivalent Availability Factor (EAF):		N/A %
	d. Resulting Capacity Factor (%):		~29 %
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):		30
	b. Total Installed Cost (In-service year $/kW):		
	c. Direct Construction Cost ($/kWac): ($2020)		
	d. AFUDC Amount ($/kW):		
	e. Escalation ($/kW):		
	f. Fixed O&M ($/kWdc-yr): ($2020)		
	g. Variable O&M ($/MWh): ($2020)		0.00
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	5/2021		
	b. Commercial in-service date:	01/2022	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2022	
	b. Commercial in-service date:		5/2023	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)		
	g. Variable O&M ($/MWh):	($2020)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2022	
	b. Commercial in-service date:		5/2023	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)		
	g. Variable O&M ($/MWh):	($2020)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2023	
	b. Commercial in-service date:		5/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)		
	g. Variable O&M ($/MWh):	($2020)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2023		
	b. Commercial in-service date:	5/2024	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)		
	g. Variable O&M ($/MWh):	($2020)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2025		
	b. Commercial in-service date:	12/2025	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2026		
	b. Commercial in-service date:	12/2026	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**Undesignated CT P1**	
(2)	Capacity			
	a. Summer (MWs):		226	
	b. Winter (MWs):		240	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2025	
	b. Commercial in-service date:		6/2027	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low Nox Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		95.06	%
	d. Resulting Capacity Factor (%):		18.6	%
	e. Average Net Operating Heat Rate (ANOHR):		10,621	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		647.4	
	c. Direct Construction Cost ($/kW):	($2020)	562.2	
	d. AFUDC Amount ($/kW):		35.3	
	e. Escalation ($/kW):		49.9	
	f. Fixed O&M ($/kW-yr):	($2020)	1.64	
	g. Variable O&M ($/MWh):	($2020)	7.26	
	h. K Factor:		NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2027	
	b. Commercial in-service date:		12/2027	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~29 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac):	($2020)		
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr):	($2020)		
	g. Variable O&M ($/MWh):	($2020)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2028		
	b. Commercial in-service date:	12/2028	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**Undesignated CT P2**	
(2)	Capacity		
	a. Summer (MWs):	226	
	b. Winter (MWs):	240	
(3)	Technology Type:	COMBUSTION TURBINE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	1/2027	
	b. Commercial in-service date:	6/2029	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	Dry Low Nox Combustion	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	UNKNOWN	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	3.00	%
	b. Forced Outage Factor (FOF):	2.00	%
	c. Equivalent Availability Factor (EAF):	95.06	%
	d. Resulting Capacity Factor (%):	18.6	%
	e. Average Net Operating Heat Rate (ANOHR):	10,621	BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	35	
	b. Total Installed Cost (In-service year $/kW):	665.3	
	c. Direct Construction Cost ($/kW): ($2020)	562.2	
	d. AFUDC Amount ($/kW):	36.3	
	e. Escalation ($/kW):	66.8	
	f. Fixed O&M ($/kW-yr): ($2020)	1.64	
	g. Variable O&M ($/MWh): ($2020)	7.26	
	h. K Factor:	NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2020

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2029		
	b. Commercial in-service date:	12/2029		(EXPECTED)
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~29	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/kW):			
	c. Direct Construction Cost ($/kWac): ($2020)			
	d. AFUDC Amount ($/kW):			
	e. Escalation ($/kW):			
	f. Fixed O&M ($/kWdc-yr): ($2020)			
	g. Variable O&M ($/MWh): ($2020)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

OSPREY

(1) POINT OF ORIGIN AND TERMINATION:	Kathleen - Osprey - Haines City East
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	50 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	6/1/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$150,000,000
(8) SUBSTATIONS:	Kathleen, Osprey, Haines City East
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

INTEGRATED RESOURCE PLANNING OVERVIEW

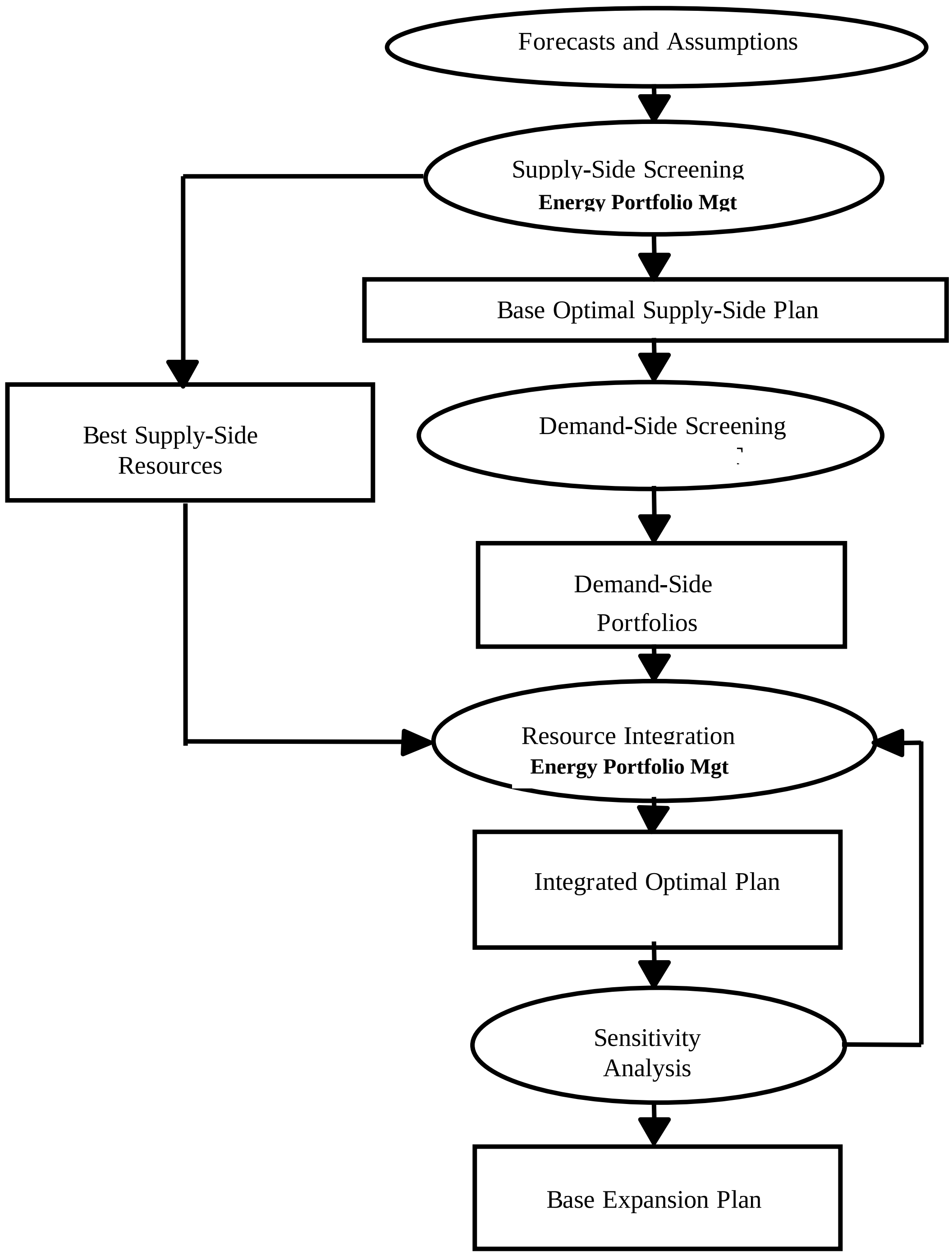
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of DEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for DEF to pursue over the next ten years to meet the Company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides DEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect DEF's view of the most likely future scenario are developed. Additional future scenarios along with high and low forecasts may also be developed. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for DEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

DEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF plans its resources to satisfy a minimum 20% Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP considers generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

DEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. DEF's resource portfolio is designed to satisfy the 20% Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20% Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and DEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters (e.g. possible climate legislation), and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the System Optimizer optimization program, a module of the Energy Portfolio Management software. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements.

Demand-Side Screening

Like supply-side resources, the impacts of potential demand-side resources are also factored into the integrated resource plan. The projected MW and MWH impacts for demand-side management resources are based on the energy efficiency measures and load management programs included in DEF's 2015 DSM Plan and meet the goals established by the Florida Public Service Commission (FPSC) in December 2019 (Docket 20190018-EG).

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives can then be optimized together with the demand-side portfolios developed in the screening process to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the Company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and reasonable revenue requirements (rates) for DEF's customers.

Developing the Base Expansion Plan

The integrated optimized plan that provides the lowest revenue requirements may then be further tested using sensitivity analysis, including High and Low Demand and Energy Forecasts (see Schedules 2 and 3). The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it would then be considered the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP. The High and Low forecasts of load and energy were provided to Resource Planning to test the robustness of the base plan.

Fuel Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in DEF's most recent planning studies were 47% debt and 53% equity capital structure, projected cost of debt of 4.35%, and an equity return of 10.5%. The assumptions resulted on a weighted average cost of capital of 7.61% and an after-tax discount rate of 7.10%.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of 1,403 MW of Solar PV generation with an expected equivalent summer firm capacity contribution of approximately 800 MW and 452 MW of new natural gas fired generation consisting of two planned combustion turbine units, one added in year 2027 and another in year 2029, at undesignated sites as well as the incorporation of the full firm capacity of the Osprey Energy Center. DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan. In this plan, DEF has assigned this DEF owned solar PV generation an equivalent summer capacity value equal to 57% of the nameplate capacity of the planned installations. This assignment assumes that the projects developed over the period of this plan will be single-axis tracking technology. We foresee that as more solar is added, the net-load peak hour will start to shift to later hours, and the solar contribution to firm capacity might decline. DEF plans to evaluate this assignment over time and may revise this value in future Site Plans based on changes in project designs and the data received from actual operation of these facilities once they are installed.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2020 through 2029. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan.

Through its ongoing planning process, DEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

DEF continues to secure renewable energy from the following facilities listed by fuel type:

Purchases from Municipal Solid Waste Facilities:

Pasco County Resource Recovery (23 MW)
Pinellas County Resource Recovery (54.8 MW)
Dade County Resource Recovery (As Available)
Lake County Resource Recovery (As Available)
Lee County Resource Recovery (As Available)

Purchases from Waste Heat from Exothermic Processes:

PCS Phosphate (As Available)
Citrus World (As Available)

Photovoltaics

DEF-owned Solar Facilities (212.85 MW)

Osceola 3.8 MW
Perry 5.1 MW
Suwannee 8.8 MW

Hamilton 74.9 MW

Trenton 74.9 MW

Lake Placid 45.0 MW

St Petersburg Pier 0.35 MW

Customer-owned renewable generation under DEF's Net Metering Tariff (about 175 MW as of 12/31/19)

DEF also has several as-available contracts utilizing solar PV technologies. As-available energy purchases are made on an hour by hour basis for which contractual commitments to the quantity, time or reliability of delivery are not required. At this time, the solar companies are projecting in-service dates beyond 2020. As of December 31, 2019, DEF had over 5,500 MW of solar projects in the various grid interconnection queues in Florida, representing over 80 active projects. While some of those projects anticipate selling to entities other than DEF, the Company continues to have the obligation to purchase uncommitted energy from those certified QFs at as-available energy rates. As a result, DEF is currently forecasting approximately 675 MW of QF as-available solar projects over a five-year period. In total, DEF is reasonably projecting over 2,500 MW of solar PV projects to be installed in the DEF territory over the next ten-year period. However, DEF continues to study and refine this projection. Project ownership proportions may change over time based on specific project economics, development details, renewable energy incentives and other factors.

DEF continues to field inquiries from potential renewable suppliers and explore whether these potential QFs can provide project commitments and reliable capacity or energy consistent with FERC Rules and the FPSC Rules, 25-17.080 through 25-17.310. DEF will continue to submit renewable contracts in compliance with all policies as appropriate.

Depending upon the mix of generators operating at any given time, the purchase of renewable energy may reduce DEF's use of fossil fuels. Renewable energy sources making firm commitments to the company can also defer or eliminate the need to construct more conventional generators. As part of DEF's integrated resource planning process, we are continually evaluating cost-effective alternatives to meet our customer's needs. DEF knows that renewable and distributed energy resources are an important part of Florida's energy future and we are committed to advancing these resources in an affordable and sustainable way. We are encouraged to see solar PV technology continue to reduce in price. As a result of the forecasts around solar PV technology, DEF has incorporated this clean energy source as an increasing supply-side resource in both DEF's near-term and long-term generation plans.

The development, construction, commissioning and initial operation of the solar projects at Perry, Osceola, Suwannee, Hamilton, the now commercial Lake Placid and Trenton, and under construction DeBary and Columbia plants have provided DEF with valuable experience in siting, contracting, constructing, operating, and integrating solar photovoltaic technology facilities on the power grid. DEF has worked with the contractors to establish necessary standards for the construction and upkeep of utility grade facilities and to develop standards necessary to ensure the reliability of local distribution systems. DEF is integrating voltage control in the transmission connected solar projects to enhance operational reliability and local transmission resiliency. In addition, DEF is incorporating the ability to place the solar facilities on Automatic Generation Control (AGC). This capability is preparing DEF for future scenarios where there is an excess of generation on the system and a need to utilize the solar resources to balance generation with demand. DEF is utilizing its operational experience and historic data from these solar resources to optimize the daily economic system dispatch, to quantify additional system flexibility needs to counteract the variability of solar generation and investigate potential fuel diversity contributions. Adding these near-term solar facilities is a natural evolution of integrating new generation technology and supplements the solar PV research and demonstration pilots operated under DEF's conservation programs. The Osceola, Perry, Suwannee, Hamilton, Lake Placid, Trenton, DeBary and Columbia arrays are shown in Figures 3.2, 3.3, 3.4, 3.5, 3.6, 3.7, 3.8, and 3.9 below.

FIGURE 3.2
Osceola Solar Site

FIGURE 3.3
Perry Solar Site

FIGURE 3.4
Suwannee Solar Site

FIGURE 3.5
Hamilton Solar Site

FIGURE 3.6
Lake Placid Solar Site

FIGURE 3.7
Trenton Solar Site

FIGURE 3.8
DeBary Solar Site

FIGURE 3.9
Columbia Solar Site

DEF's current forecast, supporting the Base Expansion Plan includes over 700 MW of DEF-owned solar PV to be under development over the next four years and over 1,500 MW over the ten-year planning horizon. As with all forecasts included here, the forecast relies heavily on the forward-looking price for this technology, the value rendered by this technology, and considerations to other emerging and conventional cost-effective alternatives, including the use of emerging battery storage technology.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. A specific discussion of DEF's review of load growth forecasts higher and lower than the base forecast can be found in the previous sections.

TRANSMISSION PLANNING

DEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form No. 715 filing, and to assure the system meets DEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Electric Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and in determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. DEF runs this analysis for contingencies that may occur at system peak and off-peak load levels, under both summer and winter conditions. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, transmission lines, or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs. As noted in the DEF reliability criteria, some remedial actions are allowed to reduce system loadings; in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

DEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID_Posted_Rev4.docx
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_4.docx

DEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev3.docx

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

DUKE ENERGY
FLORIDA

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

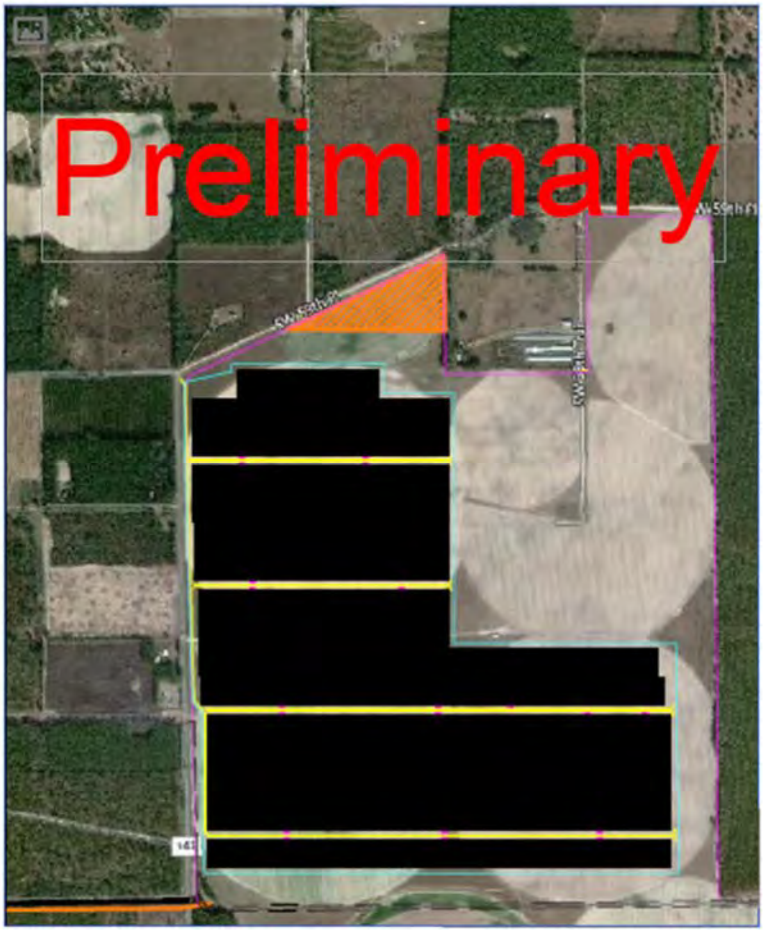
DEF's 2020 TYSP Preferred Sites include two solar generations sites; the Twin Rivers Solar Site and the Santa Fe Solar Site. These Preferred Sites are discussed below.

TWIN RIVERS SOLAR SITE

DEF has identified the Twin Rivers Solar Project, a 74.9 MWac solar single-axis tracking PV project located in Hamilton County, Florida. The site is located on former agricultural and timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV three terminal, three breaker switching station and will be connected via a generation tie-line. All environmental surveys are complete, and DEF has received the necessary special permits from Hamilton County. A Site and Development Plan approval is required from Hamilton County along with an Environmental Resource Permit from FDEP. The project expects to find a limited number of Gopher Tortoises with no other impacts to wetlands or additional species. The project is expected to start construction in early 2020 with an expected in-service date at the end of 2020 or beginning of 2021.

FIGURE 4.1

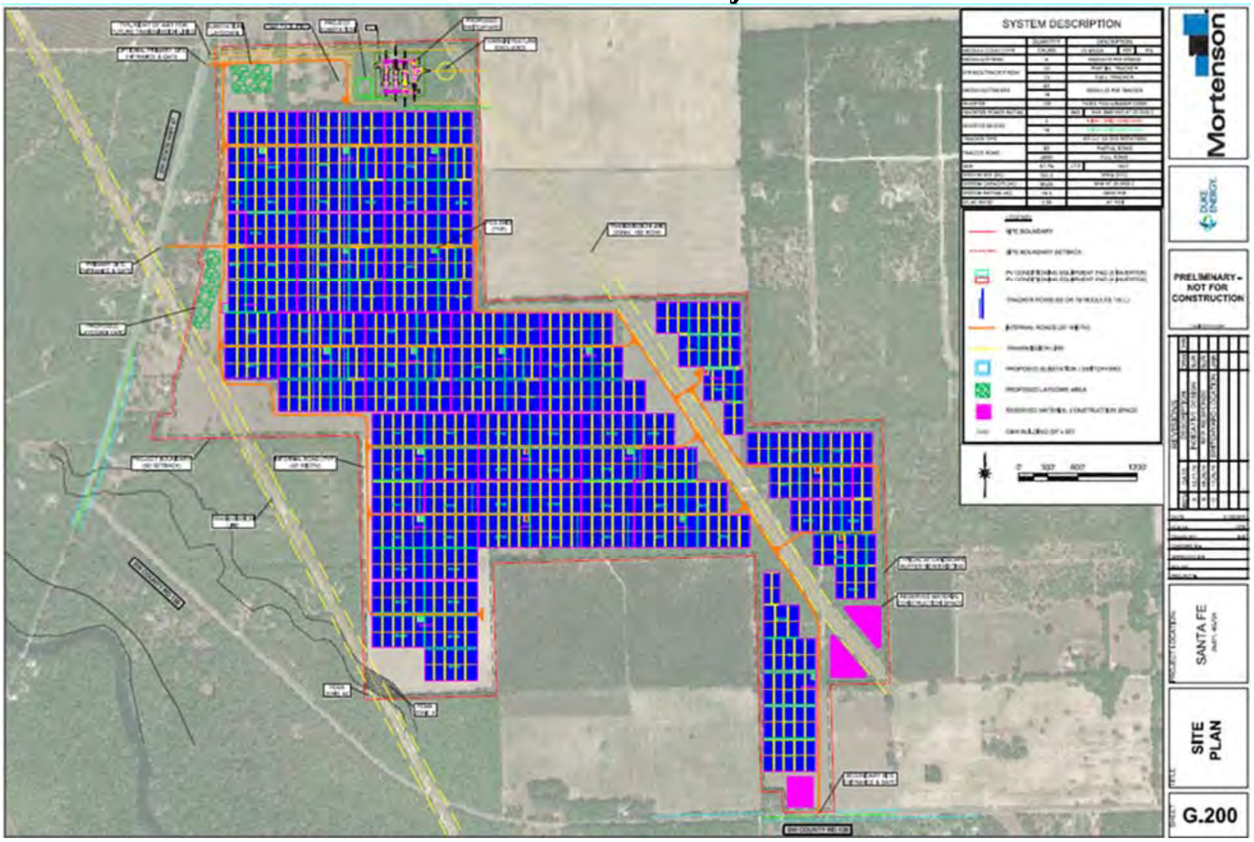
Twin Rivers Solar Project



SANTA FE SOLAR POWER PLANT

DEF has identified the Santa Fe Solar Project, a 74.9 MWac solar single-axis tracking PV project located in Columbia County, Florida. The site is a former agricultural and cattle grazing lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV three terminal, three breaker switching station and will be connected via a generation tie-line. All environmental surveys are complete, and DEF has received the necessary special use permit from Columbia County. An Environmental Resource Permit is required from FDEP, but it the responsibility of the EPC. A Gopher Tortoises relocation permit from FDEP has been received assuming 89 tortoises will need to be relocated to an already identified recipient site. There are no wetlands on site and no additional species of concern. The project is expected to start construction in early 2020 with an expected in-service date at the end of 2020.

FIGURE 4.2
Santa Fe Solar Project



A Checklist for Voluntary Utility-Led Community Solar Programs

A Guide to Evaluate and Inform Program Design and Implementation

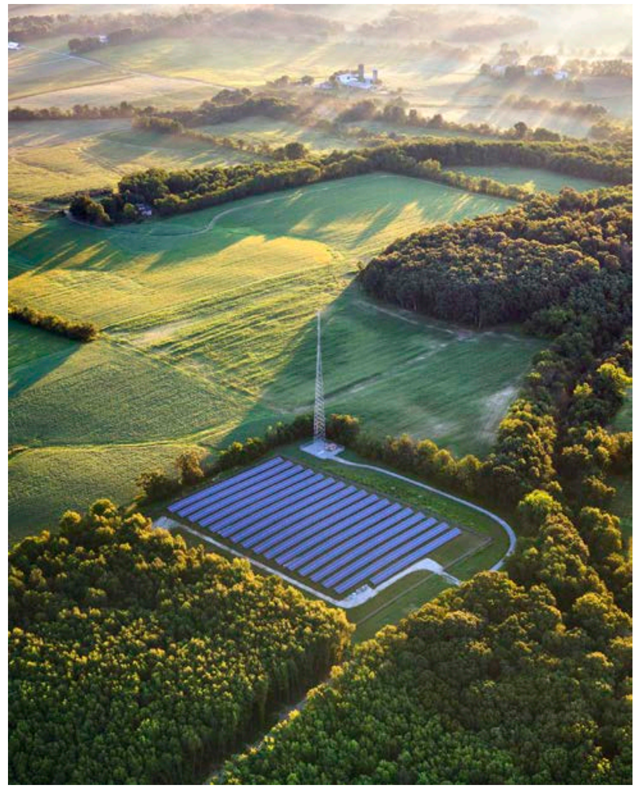
VOTE SOLAR

IREC

Vote Solar and the Interstate Renewable Energy Council, Inc.

November 2018

COMMUNITY SOLAR projects provide multiple subscribers with on-bill benefits directly attributable to that particular solar project, interconnected at the distribution level. In addition, community solar programs should result in additional incremental renewable energy resources on the distribution grid that otherwise would not have been procured by the utility to serve all customers.



Community solar now accounts for one gigawatt of installed capacity and has the potential to scale to 50-80 times that size by 2030[1], bringing widespread benefits to customers, communities, the economy and the environment. The U.S. community solar market is growing rapidly, driven by both state policy and voluntary utility programs (i.e., those programs not required by state law). Even in states that have not statutorily authorized community solar programs, all electric utilities have the option to offer voluntary programs for their customers. Nationwide, over 220 utilities offer community solar programs across 36 states, and a growing number of rural electric cooperatives, municipal utilities, and investor-owned utilities are exploring or implementing community solar program offerings[2]. Key motivations for these voluntary programs include rising customer demand for renewable energy, providing economic benefits to low- to moderate-income (LMI) customers and underserved communities, and diversifying the energy resource mix, among others.

Across the country, voluntary utility-led program offerings vary in terms of program design, structure, administration, and customer participation. In addition, company governance and regulation differ by utility, which means program development, review and the amount of non-utility stakeholder input and oversight can vary. The ability for utilities to design programs well-suited to meet their unique situations and respond to their customers' interests is important to achieve program success. However, despite their

1 GTM Research, *The Vision for U.S. Community Solar: A Roadmap to 2030,* July 2018, available at: http://www.votesolar.org/csvision.

2 Chwastyk, Dan, *From consumer interest to fully subscribed programs: SEPA report drills into details of community solar success,* Smart Electric Power Alliance, May 2018, available at: https://sepapower.org/knowledge/from-consumer-interest-to-fully-subscribed-programs-sepa-report-drills-into-details-of-community-solar-success/.

diversity, many of these programs would benefit from a common framework to improve customer understanding and acceptance of community solar and help ensure community solar can scale more quickly and cost-efficiently.

This checklist, developed by Vote Solar and the Interstate Renewable Energy Council (IREC), both national non-profit organizations, is intended to help guide utility officials and other stakeholders interested in creating new utility-led community solar programs (or those seeking to improve existing programs). Based on established practices and successful program models, this checklist reflects the program design considerations critical to supporting effective community solar programs that appeal to and benefit their customers and communities.

The goal of this checklist is to inform and guide voluntary utility-led community solar program design, such that existing and future programs adopt replicable and scalable attributes that are customer focused and support high rates of participation and capacity deployment. In addition, this checklist can help drive innovative implementation strategies that ensure more customers can access and benefit from program offerings, including those that have not traditionally benefited from on-site solar programs. The checklist focus on utility-led community solar programs is not intended to imply or recommend that these should be the only programs made available. Rather, this checklist aims to highlight the key program design considerations and provide recommendations to align programs with proven practices to replicate successes across diverse markets.

The checklist is organized into seven categories, with priority issues for program design identified within each category. The most important issues for successful programs are indicated with a blue circle. Lastly, although not articulated as a separate item in the checklist, all programs should undergo periodic review to address identified weaknesses and improve the program offering for customers.

1. EXPAND CONSUMER ACCESS TO CLEAN ENERGY

Community solar is a proven way to expand solar access to all Americans, regardless of income level or housing type. It is a critical and necessary consumer offering to meaningfully provide consumer access to clean energy, particularly for renters and underserved communities.

Establish and clearly articulate program goals and intended participants.

- Unless there is a specific goal to serve only LMI customers, affordable housing properties and/or other underserved communities, any project should allow all customer classes (e.g., residential, small commercial, large commercial, industrial, low-income, moderate-income etc.) to participate in a community solar offering.
- Ensure multiple subscribers and different customer classes (if applicable) can benefit from a single community solar array.
  - Establish a maximum subscription size (e.g., one customer may not subscribe to more than 40% of the project capacity).
  - Set participation goals for small customers (residential, small commercial) to ensure that larger customers do not subscribe for the majority of program capacity (e.g., set a goal that 40% of the project should be reserved for subscriptions of 25 kW or less).
- Conduct preliminary market research to understand customers' primary motivations for participating in a community solar program and use that to inform program design and prioritize the most compelling elements as part of the community solar offering (e.g. system location, specific ownership models, subscription terms, and customer education, marketing and outreach strategies).

☐ **Ensure that the program is appropriately sized to meet customer demand and achieve overall goals. Program capacity limits set too low may not sufficiently expand consumer access to clean energy.**

- Include an annual process for program evaluation, assessment, and adjustment in conjunction with interested stakeholders. The annual program evaluation process should include, at minimum:
  - an assessment of available capacity;
  - the opportunity for additional capacity to meet customer demand;
  - the customer value proposition;
  - the current subscriber mix;
  - the effectiveness of marketing, education and outreach strategies;
  - and the opportunity to allow non-utility providers to reach as many customers as possible.

☐ **Set participation targets for LMI customers, affordable housing providers and tenants, tenants living in multifamily housing and disadvantaged communities. These participation targets should also include a minimum goal for low-income residential participation (e.g., 20% of the program capacity should be allocated to LMI projects with at least 10% dedicated to low-income households).**[3]

- Adopt targeted program design provisions to increase LMI participation (e.g., carve-outs or targets).

☐ **Address barriers for program participation by LMI customers, affordable housing providers and tenants, tenants living in multifamily housing and disadvantaged communities.**[3,4]

- Create new or leverage existing mechanisms to address the financial barriers to participation faced by LMI customers such as: [3,4]
  - direct or indirect incentives;

3 For more information on targeted program design provisions to facilitate participation by underserved communities see Vote Solar & GR D Alternative s Low ncome Solar Policy Guide available at: https://www lowincomesolar org and REC s Shared Renewables for Low to Moderate ncome Consumers: Policy Guidelines and Model Provisions available at: https://irecusa org/publications/shared renewable ener gy for low to moderate income consumers policy guidelines and model provisions/

4 For more information on financing barriers and supportive interventions for low income community solar projects see the Sustainable Capital Advisors nclusive Solar Finance Framework report available at: https://votesolar org/policy/policy guides/low income solar access/ inclusive solar finance framework/ listed in the resources section

- subscriptions with no upfront costs;
- on-bill financing;
- alternative credit criteria;
- loan-loss reserve.

☐ **Create a plan for community outreach and education to ensure customers are aware of and understand the program.**

- Partner with community-based organizations on education, outreach, and engagement efforts to increase customer participation, particularly among the lower income customers.

☐ **Establish streamlined interconnection processes.**

- If utility-led programs are engaging third-party developers, then uniform standards, fees, and interconnection processes should be in place to facilitate project development. [5]

2. OFFER TANGIBLE ECONOMIC BENEFITS FOR ALL PARTICIPATING CUSTOMERS

The majority of customers are interested in solar as a way to save on energy costs.[6] In other words, community solar should not be viewed as a premium product. Therefore, it is critical that any community solar offering provide tangible economic benefits for all participating customers. Individuals, households, businesses and institutions that receive energy cost savings will be inclined to maintain their subscription over the life of the community solar project.

5 For additional information on streamlined interconnection processes see REC s *Model Interconnection Procedures and Priority Inter connection Considerations Memo* available at: https://irecusa org/publications/model interconnection procedures/

6 Smart Electric Power Alliance and Shelton Group *What the Community Solar Customer Wants*, August 2016 available at: https://se papower org/resource/what the community solar customer wants/ [According to the report 65 percent of households are interested in solar because they want lower monthly energy costs]



The following program design elements and specific recommendations should be considered to provide tangible economic benefits to community solar subscribers:

☐ **Structure the subscription offering for customers in a way that provides near-term and long-term economic benefits for all subscribers.**

- Individual subscribers should receive a credit on their electric utility bill as a dollar-per-kilowatt hour credit that reflects their community solar subscription.
- The value of the credit should either be value based capturing the full benefits of distributed generation for the services and benefits it provides, total applicable retail rate minus a reasonable delivery charge that takes transmission and distribution benefits into account, or equal to the applicable retail rate.[7]
- The value of the credit shall be sufficient to reasonably allow for the creation, financing and accessibility of community solar facilities to ensure robust customer participation, and be provided for the useful life of the community solar project but not less than 25 years.
- Subscriptions or participation in the program that are at a premium do not meet best practices.[8]

☐ **Eliminate upfront costs associated with any subscription.**

- Offer a "pay-as-you-go" subscription model to eliminate the upfront investment barrier to going solar.[9]
- Eliminate any upfront deposits or sign-up fees. If a utility requires these, they should either be refundable or applied to buy down the subscription cost.

7 For more information on bill credit valuation see the following resources: Coalition for Community Solar Access s *Community Solar Policy Decision Matrix,* available at: http://www communitysolaraccess org/community solar policy decision matrix 2017/; and REC s *Model Rules for Shared Renewable Energy Programs* available at: https://irecusa org/publications/model rules for shared renewable energy pro grams/

8 Any community solar program should be structured in a way that provides tangible economic benefits to subscribers Offerings at a cost premium fail to meet best practices

9 An upfront per panel purchase option can be offered alongside the "pay as you go subscription model

☐ **Ensure LMI and other underserved customers receive significant energy bill savings that can be realized immediately.**

- LMI and other underserved customers must receive immediate savings to facilitate program participation.
- LMI customers should be able to participate in the program at no upfront cost.
- Identify low-cost financing options and explore the potential for local grants or philanthropic funding.
- Explore opportunities to serve as a "backup subscriber" or facilitate the purchase of solar on behalf of low-income customers to help create an immediate value proposition to LMI participants.
- Facilitate the participation of other large entities as backup subscribers and/or "anchor tenants" to help offer tangible economic benefits for LMI households and other underserved communities.

☐ **Identify an appropriate provider of last resort so that if subscription rates drop temporarily, the amount of unsubscribed energy is minimized and the economic value of the community solar project is maintained.**

- Allow a municipal or other institutional customer's subscription to temporarily exceed the customer's average monthly usage if the customer serves as a backup subscriber, meaning the customer fills a gap in subscriptions in the event of default by one or more customers.
- The utility or anchor tenant should serve as the provider of last resort.

3. IDENTIFY WAYS TO PROMOTE PROJECT DEVELOPMENT COST SAVINGS

Any utility-led program should evaluate ways to create a cost-effective community solar project, so that any cost savings can be passed down to individual subscribers. To do this, utilities should:

☐ **Explore opportunities to reduce project development costs to provide greater economic benefits to subscribers.**

- Pursue time- and cost-efficient land acquisition strategies for multiple projects.

☐ **Identify ways to maximize economies of scale to offer tangible economic benefits.**

- Install a single, large community solar facility (at least 1 MW in size) or multiple, smaller installations (portfolio approach).

☐ **Reference Section V to find ways to promote market competition to reduce overall project development costs.**

4. PRIORITIZE THE CUSTOMER EXPERIENCE

Customer-centric community solar offerings are critical for successful programs that attract and retain subscribers, while also providing meaningful benefits to participants. Though customer preferences may vary across utilities, voluntary community solar programs should:

☐ **A community solar project and all of its subscribers must be sited within the utility's electric service territory.**[10]

☐ **Build transparency and consumer protection into community solar program administration.**

- Provide a clear, easy-to-understand disclosure form for customers that highlights key contract terms and other program details that is available in multiple languages.[11]

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10 As indicated in the SEPA and Shelton Group report entitled *What the Community Solar Customer Wants* (available in the Resources section of this report) 51% of commercial customers prefer "visible projects that do not cost a premium and residential customers highly value "visibility and access to production information

11 See New York and Minnesota s consumer disclosure forms NY s disclosure form is available here: http://www3 dps ny gov/W/PSCWeb nsf/96f0fec0b45a3c6485257688006a701a/eab5a735e908b9fe8525822f0050a299/$F LE/New%20York%20Community%20Distributed%20Generation%20Disclosure%20Form6 1 18 docx; MN s form is available here: https://www cleanenergyresourceteams org/sites/default/files/CSG Disclosure Checklist 2017 pdf

- Provide customers with clear and transparent subscription information on their bill including, at minimum:
  - kilowatt-hours generated,
  - the value of that generation,
  - billing period costs and savings,
  - cumulative costs and savings.

☐ **Streamline subscriber management, billing and communication processes.**

- Use billing software versus more inefficient manual billing techniques to make the subscriber management and associated billing more efficient.
- Initiate regular customer outreach and engagement about the program and any complementary programs.

☐ **Provide attractive and flexible subscription terms and payment options to appeal to a variety of customer preferences.**

- Flexible subscription terms should include:
  - A variety of subscription types, which could include an upfront per panel purchase option but also must include a monthly subscription-based offering, frequently called "pay-as-you-go."
  - Option for on-bill repayment and/or on-bill financing to make it easier and more economical for customers to participate.
  - No or low upfront costs (any upfront costs should be refundable or applied to the overall subscription cost).
  - Short subscription lengths: Subscribers should be able to participate on a month-to-month basis. If that is not possible, then the program should only require a minimal participation term of 1 year.
  - Portability and transferability: customers should be allowed to take their subscription with them if they move within the utility service territory (portability), or transfer their subscription if they leave the program or move out of the service territory (transferability).
  - No or low cancellation fees: If cancellation or termination fees are included in a customer's subscription, they should be waived if the subscriber has exceeded a minimum term (e.g. 1 year).

5. PROMOTE COMPETITION

Utilize competition to create the most cost efficient and consumer-focused community solar project.

☐ **Promote participation by third-party providers to drive cost savings, innovation, and competition.**

- Issue a competitive solicitation for the engineering, procurement, and construction of the solar array.
- Encourage participation by third-party providers for project financing, such as a pass-through Power Purchase Agreement.
- Encourage participation by third-party providers for program design, customer education and outreach, customer acquisition and billing support.
- Ensure that no undue preference is given to certain solar providers to maintain a competitive marketplace.
- Include a preference for using local labor at prevailing wages.

6. OPTIMIZE COMMUNITY SOLAR TO BENEFIT THE GRID AND THE COMMUNITY

As a distributed resource, community solar has the opportunity to provide additional benefits to the distribution grid. Community solar programs present an opportunity for utilities to strategically incorporate these distributed solar projects in a way that maximizes benefits the system, and the community, as a whole.

☐ **Identify opportunities to increase grid benefits through strategic project siting or pairing with other technologies and programs.**

- Locate community solar projects in strategic areas on the grid to maximize locational value and avoid more constrained locations.

- Evaluate opportunities to combine community solar with energy storage or demand response programs.
- Evaluate the opportunity for sectionalizing equipment or switches to create microgrids capable of emergency operations in stand-alone mode.

☐ **Incorporate community solar into broader grid resiliency strategies or microgrid projects.**

- Evaluate community solar in long-term integrated distribution resource planning to optimize cost-effective deployment over time.

☐ **Prioritize local community benefits in addition to grid benefits.**

- Develop projects on brownfields, landfills, in and around environmental justice communities or other unused land.
- Partner with local institutions, such as local governments or school districts, to build projects that could reduce their energy costs.
- Partner with community groups to site a community solar array in a disadvantaged community.

7. COMPLEMENT EXISTING PROGRAMS

Community solar can meet renewable energy compliance targets at low costs, combine with other energy efficiency programs to reduce household energy burden, and lift up communities through workforce development. These programs provide a unique opportunity to explore complementary measures.

- [ ] **Make the community solar program additive so that it results in additional renewable energy resources on the distribution grid that otherwise would not have been procured by the utility to serve all customers.**[12]

- [ ] **Where possible, encourage customer participation in complementary energy efficiency offerings, demand response or time-of-use rates to help further reduce customers' energy costs and energy usage, especially for participating LMI customers.**

- [ ] **Explore creative partnerships with other state programs and/or community organizations to support skills training, workforce development, and community education.**

- [ ] **Provide a community solar option for individuals on energy assistance funding or utilizing a utility rate discount subsidy. Explore leveraging energy assistance funding to support new community solar programs.**

- [ ] **Use existing programs, such as LIHEAP, to qualify low-income customers for community solar.**

12 Any program using existing clean energy facilities would not qualify as a true community solar program

RELEVANT RESOURCES

National Shared Renewables Scorecard (IREC)
Launched by IREC in May 2017 and updated annually, the Scorecard evaluates state shared renewables programs using criteria based on best practices for program design.
https://sharedrenewablesscorecard.org/

Low-Income Solar Policy Guide (GRID Alternatives & Vote Solar)
This guide provides information on various policies and programs that are creating access to solar technology and jobs nationwide. The community solar page also identifies successful strategies to ensure low-income participation.
http://www.lowincomesolar.orghttp://www.lowincomesolar.org

Shared Renewables for Low- to Moderate-Income Consumers: Policy Guidelines and Model Provisions (IREC)
This report provides information and tools for policymakers, regulators, utilities, shared renewable energy developers, program administrators and others to support the adoption and implementation of shared renewables programs specifically designed to provide tangible benefits to LMI individuals and households. The guidelines and accompanying model provisions are intended to function in tandem with IREC's existing Model Rules for Shared Renewable Energy Programs. Both available at:
https://irecusa.org/publications/shared-renewable-energy-for-low-to-moderate-income-consumers-policy-guidelines-and-model-provisions/ and https://irecusa.org/publications/model-rules-for-shared-renewable-energy-programs/

Expanding Solar Access: Pathways for Multifamily Housing (IREC)
In this guide, local governments, housing providers, utilities and other stakeholders can learn about on-site and off-site shared renewable energy programs and how those programs can offer greater solar access for renters, multifamily residents and low-to-moderate income consumers in their communities.
https://irecusa.org/expanding-solar-access-pathways-for-multifamily-housing/

Bringing the Benefits of Solar Energy to Low-Income Consumers (Clean Energy States Alliance)
This guide outlines the obstacles that low-income households face in accessing solar power and provides a detailed overview of strategies that policymakers and government agencies can use to encourage low-income solar adoption.
http://www.cesa.org/resource-library/resource/bringing-the-benefits-of-solar-energy-to-low-income-consumers

Inclusive Solar Finance Framework (Sustainable Capital Advisors)
In this report, we outline a framework that policymakers, advocates, the solar industry, community groups, and financial organizations can use to think more broadly about ways to achieve greater equity as the nation transitions to a cleaner energy economy.
https://votesolar.org/policy/policy-guides/low-income-solar-access/inclusive-solar-finance-framework/

Community Solar Program Models Report (Smart Electric Power Alliance (SEPA)
This report, funded by the US Department of Energy Solar Energy Technologies Office Solar Market Pathways Initiative, provides insights and information on community solar market development, including which kinds of community solar programs are gaining traction with cooperatives, municipal utilities, and investor-owned utilities.
https://sepapower.org/resource/community-solar-program-designs-2018-version/

Community Solar Policy Decision Matrix (Coalition for Community Solar Access)
This policy decision matrix provides an overview of important community solar program design questions, a menu of options, recommendations, and other important issues to consider for those designing and implementing programs.
http://www.communitysolaraccess.org/community-solar-policy-decision-matrix-2017/

Community Solar Value Project
This site includes a comprehensive on-line Solutions library and additional resources on solar plus battery storage or demand response, aimed primarily as a resources for utilities. It was developed with support from the U.S. Department of Energy Solar Market Pathways Initiative.
https://www.communitysolarvalueproject.com

What the Community Solar Customer Wants (SEPA and Shelton Group)
The most successful community solar programs are designed with the customer in mind. But what does a community solar customer want? The Shelton Group and SEPA conducted a nationwide survey involving over 2,000 respondents to help answer this question. This report provides quantitative results of the survey and touches on customer preferences, how these preferences vary among different customer segments, and delves into the relative importance of various model attributes.
https://sepapower.org/resource/what-the-community-solar-customer-wants/

Community Solar: Best Practices for Utilities in the South (Southern Environmental Law Center)
SELC's Solar Initiative Policy Brief highlights best practices for utility-sponsored community solar. The document covers on-bill crediting, enrollment requirements, credit rate, REC treatment, siting and several additional considerations for utility-led offerings.
https://www.southernenvironment.org/uploads/publications/CommSolar_Utility_Best_Practices.PDF

Community Solar for the Southeast Implementation Guide (North Carolina Clean Energy Technology Center)
This guide examines several issues related to community solar, focusing specifically on the unique issues faced by electric cooperatives and municipal utilities in the southeast.
https://nccleantech.ncsu.edu/wp-content/uploads/Community-Solar-for-the-Southeast-Implementation-Guide.pdf




ACKNOWLEDGEMENTS

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DEF's Response to Staff's First Set of Interrogatories, No. 1-3.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI   EXHIBIT: 18
PARTY: Huber (1) Foster (2-3)
DESCRIPTION: DEF's Response to Staff's First Set of Interrogatories, No. 1-3.
[Bates Nos. 00001-00006]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: October 21, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-3)

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Public Service Commission's ("Staff") First Set of Interrogatories to DEF (Nos. 1-3) as follows:

INTERROGATORIES

1. Please refer to the Direct Testimony of DEF witness Thomas G. Foster, page 3, lines 3-4, filed with the Petition. Please further describe the "certain administrative costs in the revenue requirements" being alluded to in this section of testimony.

Response:
Internal labor associated with program delivery, IT expense to implement the program in the billing system and on the website, marketing and REC registration fees charged by NAR.

2. Please refer to the Direct Testimony of DEF witness Foster, page 6, lines 8-15, filed with the Petition. Please provide mathematical examples showing all values and calculations used to derive the “bill credit rate” and the “monthly bill credit” being discussed in this section of testimony.

Response:

Please see files provided in response to LULAC’s 1st Request for Production of Documents question number 1. Specifically, see the file with the name “CEC 749MW Model Case – Settlement (Filing).” The bill credit rate was designed to achieve the objectives of the Program as discussed in Witness Foster and Huber’s testimony. Once the monthly subscription rate was determined, as described in Witness Foster’s testimony on page 5, the bill credit rate was developed to yield a seven-year payback assuming a 1.5% annual escalation after the third year. It was an iterative process whereby the starting bill credit rate was varied until such time as the design parameters were met. The monthly bill credit is a simple function of monthly production times the bill credit rate. This is not broken out by month but rather on an annual basis in the calculations underpinning the program development.

3. Please refer to the Direct Testimony of DEF witness Foster, page 7, lines 7-8, filed with the Petition, for the following request. Please further explain the statement: “the credit is on a per kw vs per kWh basis which removes variability on the upside or downside associated with fluctuation in plant generation.”

Response:

For the low-income subscriptions, both the subscription rate and bill credit rate are in units of ($/kW-month); so, by associating the low-income credit with the kW subscribed, as opposed to the actual KWh produced by the solar facilities, it removes the variability that occurs if the bill credit were based on KWh produced. It should simplify the Program marketing for this customer segment to reveal fixed, day-one, bill savings and should optimize the adoption by low-income participants. This is consistent with the design for low income approved as part of FPL’s Solar Together program. As discussed in Witness Foster’s testimony, the bill credit for low-income customers more than offsets the subscription fee in every month over the life of the program.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared LON HUBER, who is personally known to me, and he acknowledged before me that he provided the answer to Interrogatory Number 1, from STAFF's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-3) in Docket No. 20200176-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Lon Huber

____
Notary Public
State of North Carolina, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 2-3, from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-3) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Geoff Foster

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

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DEF’s Response to Staff’s First Production of Documents, No. 1.

Confidential DN. 11723-2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 19
PARTY: Foster
DESCRIPTION: DEF’s Response to Staff’s First Production of Documents, No. 1. Confidential DN. 11723-2020 [Bates Nos...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: October 21, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S
FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-3)

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Public Service Commission's ("Staff") First Request for Production of Documents to DEF (Nos. 1-3) as follows:

REQUEST FOR PRODUCTION OF DOCUMENTS

1. Please provide a more detailed breakdown of "Exhibit No.__(TGF-1)" (i.e. including separated capital, the weighted average cost of capital, depreciation, and any other O&M, e.g. property taxes, and the Net Operating Income multiplier/revenue expansion factor used, "system benefits," etc.) in MS Excel, cells unlocked and formulas intact.

Response:
Please see files provided in response to LULAC's First Request for Production of Documents, question number 1. Specifically, see the file named "CEC Revenue Requirements (filing)." Within this file, there are tabs that calculate the revenue requirements associated with units going into service in 2022, 2023 and 2024. These revenue requirements are summarized in the tabs labeled "CEC Rev Req" and "Tariff Model Inputs." Each individual, year's tab calculating-revenue requirements is based on a single unit cost estimate, and in the "CEC Rev Req" tab, those revenue requirements are multiplied by the number of units being placed into service in that year. This file supports the numbers in the file, "CEC 749MW Model Case – Settlement (Filing)," specifically the tab named, "Rev Rq_Benefits." That file also includes details about the system benefits and administrative costs. Further details related to the system benefits can be found in the file named, "2020-03 Variable Benefits Associated with CEC_750MWsLCOE Calc_05282020."

2. Please provide a more detailed breakdown of "Exhibit No.__(TGF-1)" (i.e. including separated capital, the weighted average cost of capital, depreciation, and any other O&M, e.g. property taxes, and the Net Operating Income multiplier/revenue expansion factor used, "system benefits," etc.) in MS Excel, cells unlocked and formulas intact, for each individual project (10 total) associated with the Clean Energy Connection Program.

Response:
Please see the response to Staff's First Request for Production of Documents, question number 1. As noted there, DEF did not specifically model in this format, but all details associated with each unit's assumed revenue requirements have been included in the documents referenced in that response.

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DEF’s Response to Staff’s Second Set of Interrogatories,

Nos. 4 – 26.

Including attachments for responses 6, 10 – 14.

8(a) & 10 (b) –

Confidential DN. 11610-2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 20
PARTY: Huber (4, 5, 6(b),18, 20 – 26) Stout (7, 8a,17 [a – e]) Borsch (9 – 11, 15, 16, 17(f), 19) Foster (6(a), 8(b-d), 12 – 14)
DESCRIPTION: DEF’s Response to Staff’s Second Set of Interrogatories, Nos. 4 – 26. Including attachments for respo...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: October 29, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 4-26)

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Public Service Commission's ("Staff") Second Set of Interrogatories to DEF (Nos. 4-26) as follows:

INTERROGATORIES

4. Please refer to DEF witness Huber's direct testimony, Page 7, Lines 14 – 18. Have local governments pre-registered for their full allocation of capacity in the Clean Energy Connection (CEC) Program? If not, how much remains unregistered?

Response:
Local governments have pre-registered for their full allocation. When the local government enrollment window closed on August 31, 2020, DEF received 185.8MW of subscription requests versus an allocation to them of 74.9MW.

5. Please refer to DEF witness Huber's direct testimony, Page 8, Table A.

a. Provide a revised table with the most up-to-date information available.
b. Explain if there have been any changes to the pre-registration program, and if so, detail all changes that have been made to the pre-registration program.

Response:

a.

Preregistration Contracts to Date (Updated 10/22/20)

	Number of Customers	**Subscription Size (MW)**	**Percent of Total Program**
Industrial	3	106.4	14.2
Commercial	6	153.7	20.5
Education	4	226.7	30.3
Government	17	74.9	10.0
Total	**30**	**561.7**	**75.0**

b. No changes have been made.

6. Please refer to DEF witness Huber's direct testimony, Page 23, Line 23 through Page 24, Line 7, and DEF witness Foster's direct testimony, Exhibit TGF-1.

a. Provide the annual and cumulative values of the administrative costs over the life of the Clean Energy Connection Program (in nominal and net present value) as a whole and for each of the following categories: Labor, IT Expenses, Marketing and NAR Registration Fees. Please provide this response in electronic (Excel) format.
b. Provide the salary, responsibilities and duties of each employee included in the administration costs.

Response:

a. Please see attached Excel file bearing Bates Number 20FL-CEC-002045.
b. The program manager labor position averages $136,429 per year over the life of the program. The primary responsibility of this role is to lead the program design and ensure the program is administered according to the FPSC approved tariff. Program manager duties include coordination with the DEF solar team, creating and maintaining a full level of subscription throughout the life of the program through marketing and other communication initiatives. Additionally, the program manager's role is to educate the DEF customer base and involved communities on program features and changes to ensure understanding and satisfaction with the program. DEF expects much of this work to occur in the low-income space where there is less familiarity with this type of program.

   The specialist labor position averages $89,259 per year over the life of the program. The primary responsibility of this role is to assist the program manager in the operation and management of the program. These duties include administrative functions surrounding the program design and standard creation process. Additionally, this role assists with individual customer inquiries regarding the program to assure satisfaction to subscribers within the program.

   The program also allocated $23,185 per year on average to account for analytical support from other groups within DEF. This allocation is used to ensure the efficiency and efficacy of the program's administration over Clean Energy Connection's lifetime.

7. Please refer to DEF witness Stout's direct testimony, Page 3, Lines 14 – 19. Please explain if there are sites being considered for both the DEF SoBRA and the CEC Program. If so, explain the process used to determine which site will be utilized for either program.

Response:
No, there are not.

REDACTED

8. Please refer to DEF witness Stout's direct testimony, Page 12, Line 17 through Page 14, Line 15.

   a. Provide an update to whether DEF has selected any site(s) for the CEC projects. If so, please identify the site(s).
   b. Please explain what opportunity, if any, there is for true-up of actual project costs compared to the estimates presented within the petition.
   c. If actual costs exceed those included in its petition, explain how DEF would seek recovery of those costs and what effects it would have on participants and non-participants. As part of your explanation, discuss whether program changes would occur to participants, such as changes in bill credits or charges. If there would be no changes to participant credits or charges, explain why not.
   d. If actual costs are below those included in its petition, explain what actions DEF would take and what effects it would have on participants and non-participants. As part of your explanation, discuss whether program changes would occur to participants, such as changes in bill credits or charges. If there would be no changes to participant credits or charges, explain why not.

<u>**Response:**</u>

a. [redacted]

[redacted]

[redacted]

b. Approval of DEF's Program includes approval of the design of the Program as well as construction of the 10 units at the estimated cost. As described in DEF's petition and testimony, these units will be included in rate base and so will be subject to prudence review if actual costs come in higher than projected and DEF seeks to include this difference in rate base in a future rate case. To the extent the units come on-line at or below the estimated cost, no additional prudence review will be necessary. DEF has exercised, and will continue to exercise, cost-control measures to ensure that its CEC Program solar facilities are constructed at or below the projected costs.

c. Please see response to 8b above. Absent the CEC program, any cost changes for the construction of the units, including the benefits of completing the project above or below budget, as well as other changes in the assumed costs, would flow to the general body of customers. The existence of the CEC program does not change this basic concept; any cost changes (both under and over runs) would flow to the general body of customers. The CEC program, like FPL's recently approved program, sets a value stream based on estimated costs and savings associated with the new solar units. While actual costs and savings will vary from estimates, program participants are signing on to the defined values included in the tariff, so participants will not have their subscription fees or bill credits impacted, but they will see the upside or downside of any changes from estimates since participants are included in the general body of customers. The CEC program was designed to have participants pay for more than 100% of the fixed costs over the life of the program and giving the general body of customers ~87% of the total savings associated with the new units. In order to maintain the Programs' integrity, DEF would not make any program changes to participants, such as bill credits or subscription fees.

d. Please see response to 8b and c above.

9. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4 and LULAC witness Rabago's direct testimony, Exhibit KKR-5.

a. Please explain whether the projected unit analysis includes the Utility's planned solar projects associated with the Solar Base Rate Adjustment mechanism included in DEF's 2017 Settlement Agreement. If not, explain why not.
b. Please explain any differences between Schedule 8 of DEF's 2020 Ten-Year Site Plan and the revised No CEC Resource Plan.

Response:

a. Yes. Both the CEC and no CEC portfolios include the planned solar projects associated with the Solar Base Rate Adjustment included in the 2017 settlement.
b. The purpose of the two plans developed and presented in this filing is to analyze the cost effectiveness and value of the CEC Project. In order to make this analysis, the alternative resources are constrained to restrict the addition of solar units after CEC. Schedule 8 of the TYSP represents proposed unit additions intended to demonstrate a best resource plan over the ten-year period. One of the key differences between these plans is that the plan presented in Schedule 8 projects the continued addition of solar resources beyond 2024. The CEC Solar plan presented in this filing accelerates approximately 300 MW of solar resources from future years into 2023 and 2024. These resources are evaluated in terms of their cost effectiveness as a part of CEC. Thus, the two plans cannot be directly compared.

10. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4.

a. Provide the estimated seasonal net firm peak demand, total available capacity and reserve margin for each year of the proposed project life, for each resource plan, with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter/Summer]			
Scenario	With CEC Units / Without CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)

b. Provide the annual change in each season's total capacity available caused by unit additions, retirements, and uprates/derates. Identify both the unit(s) and megawatts associated with each, for each year of the proposed project life, for each resource plan, with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter/Summer]		
Scenario	With CEC Units / Without CEC Units		
Year	Unit Additions	Retirements	Uprates/Downrates

Response:

a. Please see attached Excel file bearing Bates Numbers 20FL-CEC-002046 - 20FL-CEC-002047.

Season	[Winter]			
Scenario	Without CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	9,406	12,933	3,528	37.5%
2021	8,789	12,889	4,101	46.7%
2022	9,167	12,465	3,298	36.0%
2023	8,922	12,465	3,543	39.7%
2024	9,012	12,350	3,339	37.0%
2025	8,777	12,068	3,291	37.5%
2026	8,880	11,726	2,846	32.0%
2027	8,941	11,726	2,785	31.1%
2028	9,003	11,049	2,046	22.7%
2029	9,038	11,288	2,250	24.9%
2030	9,091	11,288	2,197	24.2%
2031	9,036	11,297	2,261	25.0%
2032	9,222	11,297	2,075	22.5%
2033	9,249	11,536	2,287	24.7%
2034	9,316	11,536	2,221	23.8%
2035	9,379	11,730	2,350	25.1%
2036	9,075	11,730	2,655	29.3%
2037	9,109	11,342	2,232	24.5%
2038	9,173	11,342	2,169	23.6%
2039	9,236	11,677	2,442	26.4%
2040	9,338	11,677	2,339	25.0%
2041	9,358	11,917	2,558	27.3%
2042	9,336	11,917	2,581	27.6%
2043	9,491	12,269	2,778	29.3%
2044	9,594	12,269	2,675	27.9%
2045	9,606	12,587	2,981	31.0%
2046	9,673	12,541	2,868	29.7%

Season	[Summer]			
Scenario	Without CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	8,915	11,934	3,019	33.9%
2021	8,946	11,553	2,607	29.1%
2022	9,007	11,669	2,662	29.6%
2023	8,735	11,667	2,931	33.6%
2024	8,769	11,406	2,637	30.1%
2025	8,588	11,289	2,701	31.4%
2026	8,612	11,012	2,400	27.9%
2027	8,666	10,491	1,825	21.1%
2028	8,759	10,671	1,912	21.8%
2029	8,829	10,669	1,840	20.8%
2030	8,904	10,693	1,788	20.1%
2031	8,940	10,691	1,751	19.6%
2032	9,031	10,915	1,884	20.9%
2033	9,102	10,913	1,811	19.9%
2034	9,191	11,157	1,966	21.4%
2035	9,283	11,156	1,873	20.2%
2036	8,984	10,842	1,858	20.7%
2037	9,067	10,840	1,772	19.5%
2038	9,220	11,201	1,982	21.5%
2039	9,294	11,200	1,905	20.5%
2040	9,405	11,424	2,018	21.5%
2041	9,494	11,422	1,928	20.3%
2042	9,570	11,694	2,124	22.2%
2043	9,679	11,692	2,014	20.8%
2044	9,985	12,002	2,017	20.2%
2045	9,881	12,006	2,126	21.5%
2046	9,985	11,998	2,013	20.2%

Season	[Winter]			
Scenario	With CEC Units			
Year	Net Firm Peak Demand (MW)	Total Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	9,406	12,933	3,528	37.5%
2021	8,789	12,889	4,101	46.7%
2022	9,167	12,465	3,298	36.0%
2023	8,922	12,465	3,543	39.7%
2024	9,012	12,350	3,339	37.0%
2025	8,777	12,068	3,291	37.5%
2026	8,880	11,726	2,846	32.0%
2027	8,941	11,726	2,785	31.1%
2028	9,003	10,809	1,806	20.1%
2029	9,038	10,809	1,771	19.6%
2030	9,091	11,049	1,958	21.5%
2031	9,036	10,818	1,782	19.7%
2032	9,222	11,057	1,835	19.9%
2033	9,249	11,057	1,808	19.6%
2034	9,316	11,297	1,981	21.3%
2035	9,379	11,251	1,871	19.9%
2036	9,075	11,251	2,176	24.0%
2037	9,109	11,102	1,993	21.9%
2038	9,173	11,102	1,930	21.0%
2039	9,236	11,198	1,963	21.2%
2040	9,338	11,198	1,860	19.9%
2041	9,358	11,438	2,079	22.2%
2042	9,336	11,438	2,102	22.5%
2043	9,491	11,790	2,299	24.2%
2044	9,594	11,790	2,196	22.9%
2045	9,606	12,108	2,502	26.0%
2046	9,673	12,062	2,389	24.7%

Season	[Summer]			
Scenario	With CEC Units			
Year	Net Firm Peak Demand (MW)	Total Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	8,915	11,934	3,019	33.9%
2021	8,946	11,553	2,607	29.1%
2022	9,007	11,754	2,747	30.5%
2023	8,735	11,922	3,187	36.5%
2024	8,769	11,831	3,062	34.9%
2025	8,588	11,712	3,124	36.4%
2026	8,612	11,433	2,821	32.8%
2027	8,666	10,684	2,018	23.3%
2028	8,759	10,636	1,877	21.4%
2029	8,829	10,858	2,028	23.0%
2030	8,904	10,654	1,749	19.6%
2031	8,940	10,876	1,936	21.7%
2032	9,031	10,872	1,841	20.4%
2033	9,102	11,094	1,992	21.9%
2034	9,191	11,110	1,919	20.9%
2035	9,283	11,106	1,824	19.6%
2036	8,984	11,016	2,032	22.6%
2037	9,067	11,012	1,945	21.5%
2038	9,220	11,146	1,927	20.9%
2039	9,294	11,142	1,848	19.9%
2040	9,405	11,364	1,959	20.8%
2041	9,494	11,361	1,867	19.7%
2042	9,570	11,631	2,061	21.5%
2043	9,679	11,627	1,949	20.1%
2044	9,985	11,935	1,950	19.5%
2045	9,881	11,937	2,057	20.8%
2046	9,985	12,153	2,168	21.7%

b. Please see attached Excel file bearing Bates Numbers 20FL-CEC-002048 - 20FL-CEC-002049.

11. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in nominal and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed below. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario.
b. Mid Fuel Scenario.
c. High Fuel Scenario.

[Scenario Name] – ([Nominal / NPV] $ millions)															
Year	CEC Units				Remainder of System								System Total (without carbon)	Emissions (Carbon-related)	System Total (with Carbon)
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas	Start Up &	O&M	Emissions (Non-carbon)	Total			
2020															
…															
Total															

Response:
Please see attached Excel file bearing Bates Numbers 20FL-CEC-002050 - 20FL-CEC-002058.

12. Please efer to DEF witness Foster's direct testimony, Exhibit TGF-1. Provide the annual and cumulative net system savings, CEC program administrative costs, subscription fees, bill credits, and remaining net system savings (in nominal and net present value) over the life of the proposed CEC projects for each of the scenarios listed below. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario.
b. Mid Fuel Scenario.
c. High Fuel Scenario.

System Benefits and CEC Program Impacts - [Nominal $] or [NPV $]					
Year	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fees	DEF CEC Bill Credits	Remaining Net System Savings
2020					
…					
Total					

Response:
Please see attached Excel file bearing Bates Numbers 20FL-CEC-002059 - 20FL-CEC-002061.

13. Please refer to DEF witness Huber's direct testimony Page 18, Lines 10 – 12 and Staff Interrogatory No. 11. Provide the estimated monthly residential bill impact (1,000 kWh/mo usage) of the CEC projects for each of the scenarios listed below, excluding the impacts of program administrative costs, bill credits, and/or subscription fees. This monthly bill impact should be provided for each year of the program's life. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario.
b. Mid Fuel Scenario.
c. High Fuel Scenario.

Residential Customer Bill Savings ($/1000-kWh/mo)			
Scenario	[Low Fuel / Mid Fuel / High Fuel]		
Year	Base Rates	Clauses	Total
2020			
…			

<u>Response</u>:
Please see attached Excel file bearing Bates Numbers 20FL-CEC-002062 - 20FL-CEC-002064.

14. Please refer to DEF witness Huber's direct testimony Page 18, Lines 10 – 12 and Staff Interrogatory No. 12. Provide the estimated monthly residential bill impact (1,000 kWh/mo usage) of the CEC projects for each of the scenarios listed below, including the impacts of program administrative costs, bill credits, and/or subscription fees, for each class of customer: Participant, Low-Income Participant, and Non-Participant. This monthly bill impact should be provided for each year of the program's life. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario.
b. Mid Fuel Scenario.
c. High Fuel Scenario.

Residential Customer Bill Savings ($/1000-kWh/mo)					
Scenario	[Low Fuel / Mid Fuel / High Fuel]				
Customer Type	[Participant / Low-Income Participant / Non-Participant]				
Year	Base Rates	Clauses	Subscription Fee	Bill Credits	Total
2020					
…					

<u>Response</u>:
Please see attached Excel file bearing Bates Numbers 20FL-CEC-002065 - 20FL-CEC-002068.

15. Please refer to DEF's Petition, Exhibit A, Stipulation Paragraph 3.

a. Please explain if, prior to the Stipulation, DEF considered solar storage facilities as firm capacity in resource planning.
b. Please explain if DEF has avoided or deferred any traditional generating units with solar additions prior to this proceeding. If so, please provide a list of the dockets in which this occurred and explain the circumstances, the solar addition MW, avoided MW and the type of generation avoided.
c. Please explain if counterparties will assist DEF in resource selection. If so, please describe in which ways DEF will consider counterparties input.

Response:

a. DEF considers that its PV solar facilities, such as those constructed under the terms of the Solar Base Rate Adjustment mechanism included in DEF's 2017 Settlement and those contemplated in CEC, have some firm capacity value. This value depends on the facility design and its place in the DEF generation portfolio. DEF has also considered storage paired with solar facilities to increase the capacity value of those solar facilities.
b. Each tranche of solar facilities constructed under the terms of the Solar Base Rate Adjustment mechanism included in DEF's 2017 Settlement defers conventional generating units. The solar capacity does not defer or eliminate a specific unit but has an overall effect of deferring needs throughout the plan. The comparative resource plans included in these filings show the resources deferred:
   - Docket 20180149-EI Re: DEF 1st SoBra Request for Cost Recovery; 149.8 MW
   - Docket 20190072-EI Re: DEF 2nd SoBra Request for Cost Recovery; 194.4 MW
   - Docket 20200153-EI Re: DEF 3rd SoBRa Request for Cost Recovery; 355.8 MW
c. DEF does not anticipate that the counterparties will assist DEF in resource Selection. As identified in the Stipulation, DEF has committed to evaluating certain resources and their impact on future resource plans. DEF will consider the counterparties input on evaluation inputs such as the projected cost and performance of the resources evaluated.

16. Please refer to DEF's Petition, Exhibit A, Stipulation Paragraph 4.

a. Does DEF plan to share the collected information with the FPSC? If so, when? If not, why not?
b. What are DEF's current sources of data regarding economic, operational benefits and costs of customer owned solar PV generation?
c. Please confirm that the abbreviation "NM" refers to Net Metering. If not, please explain what the abbreviation NM stands for.

Response:

a. As part of DEF's 2017 Second Revised and Restated Settlement Agreement in paragraph 33, DEF committed to collect data on the economic and operational benefits and costs, to the extent such benefits and costs can be reasonably identified, from the use of demand-side solar on its system to support overall rate design. Currently, DEF's approach to fulfill this commitment is underway and includes an initiative to install a research-sized sample of production meters and on demand-side solar generators. DEF is continuing to install solar generation meters with data acquisition technology that may provide useful information about how customers with onsite solar generators use the power grid compared to their electric usage or loading at their premise at a data collection frequency interval that may support future rate design. In the future, this data can be shared as DEF seeks relevant changes during associated rate-design proceedings and in accordance with the timing set forth in DEF's 2017 Second Revised and Restated Settlement Agreement in Section 33, and the Clean Energy Connection Stipulation in paragraph 4.
b. Please see DEF's demand-side solar generation metering explanation above related to this ongoing initiative.
c. Yes, the abbreviation "NM" in the Clean Energy Connection Stipulation in paragraph 4 refers to net metering.

17. Please refer to DEF’s Petition, Exhibit A, Stipulation Paragraphs 5 – 8.

a. Please refer to Paragraph 5. Please explain if the proposed competitive solicitation process differs from DEF’s current approach towards solar generation construction and acquisition. If so, please detail the differences.
b. Please refer to Paragraphs 5(a) and (b). Please verify if the values referred to are binding in any way on DEF.
c. Please refer to Paragraph 6. Please explain if the proposed considerations for project acquisition differs from DEF’s current approach towards solar generation acquisitions. If so, please detail the differences.
d. Please refer to Paragraph 7. Please explain if the proposed evaluation process differs from DEF’s current approach towards solar generation construction and acquisition. If so, please detail the differences.
e. Please refer to Paragraph 8. Please explain if the proposed consideration of third party developments/acquisitions differs from DEF’s current approach towards solar generation construction and acquisition. If so, please detail the differences.
f. Please refer to Paragraph 8(b). Please explain if solar purchase power agreements would be eligible for similar treatment under the terms of this stipulation. If not, why not?

Response:

a. DEF’s approach has not changed. DEF conducts requests for proposals for all major equipment and for the engineering, procurement and construction contract (“EPC Contract”). DEF considers both greenfield and third-party sited projects for solar generation construction and acquisition.
b. No. 5a was intended to be an example of the project value stack for a typical solar project for this program. 5b was intended to be an example of the value of the solar panels relative to the total project costs.
c. No. The considerations proposed for project acquisition are the same used for the SOBRA project acquisitions.
d. No. The valuation process detailed in Paragraph 7 describes several key attributes of high-quality solar projects. The proposed evaluation process is not different from the current approach in its aim to select and build the most cost-effective solar projects.
e. No. The proposed considerations are the same.
f. Given the timing, certainty, and control necessary to meet DEF’s customer demand and expectations of the comprehensive CEC Program, solar purchased power agreements are not under consideration for the Program; therefore, under the Stipulation for the CEC Program, DEF is focused on working with third parties at various stages of project development to deliver quality projects that will benefit all customers over the 30-year Program period. Even if it were practical, where DEF could work with all third parties as described in paragraph 8(b) of the Stipulation, there are no guarantees under a solar purchased power agreement that the project’s financial and operational management over the long-term would be maintained consistent with the needs of the Program and therefore put the Program’s success at risk including the clean energy commitment to all DEF customers.

18. Please refer to DEF's Petition, Exhibit A, Stipulation Paragraph 9.

a. Please explain why the add-on program would be limited to only large CEC participants. As a part of this explanation, please explain why either smaller CEC or non-CEC participants could not participate.
b. If DEF's analysis shows that the program is not in the public interest, will the results of the analysis be presented to the FPSC? If so, when? If not, why not?
c. Does DEF plan to seek recovery of this add-on program? If so, under what mechanism(s) would the Company seek recovery?

<u>Response</u>:

a. While no program structure has been defined at this time, the goal is to use storage to promote public health and safety.
b. Yes, DEF plans to present the findings upon study completion and share the results to the FPSC if so desired.
c. No program structure has been defined at this time.

19. Please refer to DEF witness Huber's direct testimony, Page 19, Lines 7 – 8. Does DEF intend to couple any of the planned CEC projects with storage?

a. If yes, please explain how the performance of the storage technology would impact CEC participants as well as the general body of ratepayers.
b. If yes, could adding storage effectively increase the capacity of the program?

Response:

a. No.
b. As noted in the response to 19a, the CEC program does not contemplate coupling storage with the proposed CEC solar projects. DEF continues to evaluate the opportunity for storage, either coupled with solar projects or independently sited, to provide system capacity and to enhance the value of intermittent resources. As these evaluations demonstrate cost-effective opportunities bringing value to the system for DEF customers, DEF would bring such projects forward in a subsequent proceeding.

For questions 20-25, please refer to the DEF's Petition, Exhibit A, Stipulation, Paragraph 9.

20. Does DEF intend to seek cost recovery for conducting this study? If yes, in what manner?

    a. Please provide an estimated cost to conduct this study.

Response:
DEF plans to conduct this study internally.

21. Please explain if this add-on program would be implemented through a new tariff offering. If not, please explain why.

Response:
No program structure has been defined at this time.

22. Please explain if customer participation would be limited to CEC participants. If yes, please explain why.

Response:
No program structure has been defined at this time.

23. Please explain if the storage technologies would be customer or utility owned.

Response:
No program structure has been defined at this time.

24. Please explain if DEF would allow the storage technologies to be coupled to the grid and able to deliver power to the Utility.

Response:
No program structure has been defined at this time.

25. Please explain if DEF would limit the capacity and/or operation of the storage technology?

Response:
No program structure has been defined at this time.

26. Please explain if customers would be eligible to receive bills credits or incentives for these storage technologies. If yes, please explain what type of incentives DEF would offer?

Response:
No program structure has been defined at this time.

	Program Administration Costs Revenue Requirement (Nominal $)				
	IT Costs	Labor	Marketing	NAR Registration Fees	Total Program Administration
2020	0.0	0.0	0.0	0.0	0.0
2021	196,322.0	282,880.2	536,876.9	4,000.0	1,020,079.1
2022	182,854.3	343,356.7	79,716.6	21,609.0	627,536.5
2023	169,450.1	362,515.1	79,716.6	71,394.4	683,076.2
2024	157,670.1	334,848.2	74,149.7	108,045.0	674,712.9
2025	146,042.3	344,893.6	57,216.6	108,045.0	656,197.4
2026	0.0	355,240.4	47,216.6	108,045.0	510,502.0
2027	0.0	365,897.7	91,149.7	108,045.0	565,092.3
2028	0.0	376,874.6	39,216.6	108,045.0	524,136.1
2029	0.0	388,180.8	49,216.6	108,045.0	545,442.3
2030	0.0	399,826.3	81,149.7	108,045.0	589,020.9
2031	0.0	215,140.7	49,216.6	108,045.0	372,402.2
2032	0.0	221,594.9	39,216.6	108,045.0	368,856.4
2033	0.0	228,242.7	91,149.7	108,045.0	427,437.3
2034	0.0	235,090.0	39,216.6	108,045.0	382,351.5
2035	0.0	242,142.7	49,216.6	108,045.0	399,404.2
2036	0.0	249,407.0	81,149.7	108,045.0	438,601.6
2037	0.0	256,889.2	49,216.6	108,045.0	414,150.7
2038	0.0	264,595.9	39,216.6	108,045.0	411,857.4
2039	0.0	272,533.8	91,149.7	108,045.0	471,728.4
2040	0.0	280,709.8	39,216.6	108,045.0	427,971.3
2041	0.0	289,131.1	49,216.6	108,045.0	446,392.6
2042	0.0	297,805.0	81,149.7	108,045.0	486,999.6
2043	0.0	306,739.2	49,216.6	108,045.0	464,000.7
2044	0.0	315,941.3	39,216.6	108,045.0	463,202.8
2045	0.0	325,419.6	91,149.7	108,045.0	524,614.2
2046	0.0	335,182.2	2,500.0	108,045.0	445,727.1
2047	0.0	345,237.6	27,500.0	108,045.0	480,782.6
2048	0.0	355,594.8	2,500.0	108,045.0	466,139.7
2049	0.0	366,262.6	27,500.0	104,045.0	497,807.6
2050	0.0	377,250.5	2,500.0	108,045.0	487,795.4
2051	0.0	388,568.0	27,500.0	108,045.0	524,112.9
2052	0.0	400,225.0	2,500.0	90,436.0	493,161.0
2053	0.0	412,231.8	27,500.0	55,218.0	494,949.8

	Program Administration Costs Revenue Requirement (PV $)				
	IT Costs	Labor	Marketing	NAR Registration Fees	Total Program Administration
2020	0.0	0.0	0.0	0.0	0.0
2021	183,994.4	265,117.3	503,164.9	3,748.8	956,025.4
2022	160,611.4	301,589.8	70,019.6	18,980.4	551,201.2
2023	139,491.8	298,423.4	65,622.9	58,772.0	562,310.1
2024	121,644.3	258,339.2	57,207.3	83,357.9	520,548.6
2025	105,598.2	249,380.8	41,371.3	78,123.6	474,474.0
2026	0.0	240,733.1	31,996.9	73,218.0	345,948.1
2027	0.0	232,385.3	57,890.1	68,620.4	358,895.8
2028	0.0	224,327.0	23,342.9	64,311.6	311,981.4
2029	0.0	216,548.1	27,455.6	60,273.3	304,277.0
2030	0.0	209,038.9	42,427.0	56,488.5	307,954.4
2031	0.0	105,417.8	24,115.8	52,941.5	182,475.1
2032	0.0	101,762.3	18,009.3	49,617.1	169,388.6
2033	0.0	98,233.5	39,229.9	46,501.5	183,964.9
2034	0.0	94,827.1	15,818.6	43,581.5	154,227.2
2035	0.0	91,538.8	18,605.7	40,844.9	150,989.4
2036	0.0	88,364.5	28,751.2	38,280.2	155,395.9
2037	0.0	85,300.3	16,342.4	35,876.4	137,519.2
2038	0.0	82,342.4	12,204.2	33,623.7	128,170.3
2039	0.0	79,487.0	26,584.7	31,512.3	137,584.0
2040	0.0	76,730.7	10,719.7	29,533.6	116,983.9
2041	0.0	74,069.9	12,608.4	27,679.1	114,357.4
2042	0.0	71,501.4	19,483.6	25,941.0	116,926.1
2043	0.0	69,022.0	11,074.6	24,312.1	104,408.8
2044	0.0	66,628.6	8,270.3	22,785.5	97,684.4
2045	0.0	64,318.1	18,015.4	21,354.7	103,688.2
2046	0.0	62,087.8	463.1	20,013.8	82,564.7
2047	0.0	59,934.8	4,774.1	18,757.1	83,466.0
2048	0.0	57,856.4	406.8	17,579.3	75,842.5
2049	0.0	55,850.2	4,193.4	15,865.5	75,909.0
2050	0.0	53,913.5	357.3	15,440.9	69,711.6
2051	0.0	52,043.9	3,683.3	14,471.3	70,198.5
2052	0.0	50,239.2	313.8	11,352.2	61,905.2
2053	0.0	48,497.1	3,235.2	6,496.1	58,228.5

	Program Administration Costs Revenue Requirement (CPV $)				
	IT Costs	Labor	Marketing	NAR Registration Fees	Total Program Administration
2020	0.0	0.0	0.0	0.0	0.0
2021	183,994.4	265,117.3	503,164.9	3,748.8	956,025.4
2022	344,605.8	566,707.1	573,184.5	22,729.2	1,507,226.6
2023	484,097.6	865,130.5	638,807.3	81,501.3	2,069,536.7
2024	605,741.9	1,123,469.7	696,014.6	164,859.2	2,590,085.4
2025	711,340.1	1,372,850.6	737,386.0	242,982.8	3,064,559.4
2026	711,340.1	1,613,583.7	769,382.9	316,200.8	3,410,507.4
2027	711,340.1	1,845,969.0	827,272.9	384,821.3	3,769,403.3
2028	711,340.1	2,070,296.0	850,615.8	449,132.8	4,081,384.7
2029	711,340.1	2,286,844.1	878,071.4	509,406.1	4,385,661.7
2030	711,340.1	2,495,883.0	920,498.4	565,894.6	4,693,616.1
2031	711,340.1	2,601,300.8	944,614.3	618,836.1	4,876,091.2
2032	711,340.1	2,703,063.0	962,623.6	668,453.2	5,045,479.8
2033	711,340.1	2,801,296.5	1,001,853.5	714,954.7	5,229,444.8
2034	711,340.1	2,896,123.6	1,017,672.1	758,536.2	5,383,672.0
2035	711,340.1	2,987,662.4	1,036,277.7	799,381.2	5,534,661.3
2036	711,340.1	3,076,026.9	1,065,028.9	837,661.3	5,690,057.2
2037	711,340.1	3,161,327.2	1,081,371.3	873,537.8	5,827,576.4
2038	711,340.1	3,243,669.6	1,093,575.6	907,161.4	5,955,746.7
2039	711,340.1	3,323,156.7	1,120,160.2	938,673.7	6,093,330.7
2040	711,340.1	3,399,887.4	1,130,879.9	968,207.3	6,210,314.6
2041	711,340.1	3,473,957.3	1,143,488.2	995,886.4	6,324,672.0
2042	711,340.1	3,545,458.7	1,162,971.8	1,021,827.4	6,441,598.1
2043	711,340.1	3,614,480.8	1,174,046.5	1,046,139.6	6,546,006.9
2044	711,340.1	3,681,109.3	1,182,316.8	1,068,925.1	6,643,691.2
2045	711,340.1	3,745,427.4	1,200,332.2	1,090,279.8	6,747,379.5
2046	711,340.1	3,807,515.2	1,200,795.3	1,110,293.6	6,829,944.1
2047	711,340.1	3,867,449.9	1,205,569.4	1,129,050.7	6,913,410.1
2048	711,340.1	3,925,306.4	1,205,976.2	1,146,629.9	6,989,252.6
2049	711,340.1	3,981,156.5	1,210,169.6	1,162,495.4	7,065,161.6
2050	711,340.1	4,035,070.0	1,210,526.9	1,177,936.3	7,134,873.2
2051	711,340.1	4,087,113.9	1,214,210.2	1,192,407.6	7,205,071.7
2052	711,340.1	4,137,353.1	1,214,524.0	1,203,759.8	7,266,976.9
2053	711,340.1	4,185,850.2	1,217,759.2	1,210,255.9	7,325,205.4

10. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4

a. Provide the estimated seasonal net firm peak demand, total available capacity and reserve margin for each year of the proposed project life, for each resource plan,
with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter]			
Scenario	Without CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	9,406	12,933	3,528	37.5%
2021	8,789	12,889	4,101	46.7%
2022	9,167	12,465	3,298	36.0%
2023	8,922	12,465	3,543	39.7%
2024	9,012	12,350	3,339	37.0%
2025	8,777	12,068	3,291	37.5%
2026	8,880	11,726	2,846	32.0%
2027	8,941	11,726	2,785	31.1%
2028	9,003	11,049	2,046	22.7%
2029	9,038	11,288	2,250	24.9%
2030	9,091	11,288	2,197	24.2%
2031	9,036	11,297	2,261	25.0%
2032	9,222	11,297	2,075	22.5%
2033	9,249	11,536	2,287	24.7%
2034	9,316	11,536	2,221	23.8%
2035	9,379	11,730	2,350	25.1%
2036	9,075	11,730	2,655	29.3%
2037	9,109	11,342	2,232	24.5%
2038	9,173	11,342	2,169	23.6%
2039	9,236	11,677	2,442	26.4%
2040	9,338	11,677	2,339	25.0%
2041	9,358	11,917	2,558	27.3%
2042	9,336	11,917	2,581	27.6%
2043	9,491	12,269	2,778	29.3%
2044	9,594	12,269	2,675	27.9%
2045	9,606	12,587	2,981	31.0%
2046	9,673	12,541	2,868	29.7%

Season	[Summer]			
Scenario	Without CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	8,915	11,934	3,019	33.9%
2021	8,946	11,553	2,607	29.1%
2022	9,007	11,669	2,662	29.6%
2023	8,735	11,667	2,931	33.6%
2024	8,769	11,406	2,637	30.1%
2025	8,588	11,289	2,701	31.4%
2026	8,612	11,012	2,400	27.9%
2027	8,666	10,491	1,825	21.1%
2028	8,759	10,671	1,912	21.8%
2029	8,829	10,669	1,840	20.8%
2030	8,904	10,693	1,788	20.1%
2031	8,940	10,691	1,751	19.6%
2032	9,031	10,915	1,884	20.9%
2033	9,102	10,913	1,811	19.9%
2034	9,191	11,157	1,966	21.4%
2035	9,283	11,156	1,873	20.2%
2036	8,984	10,842	1,858	20.7%
2037	9,067	10,840	1,772	19.5%
2038	9,220	11,201	1,982	21.5%
2039	9,294	11,200	1,905	20.5%
2040	9,405	11,424	2,018	21.5%
2041	9,494	11,422	1,928	20.3%
2042	9,570	11,694	2,124	22.2%
2043	9,679	11,692	2,014	20.8%
2044	9,985	12,002	2,017	20.2%
2045	9,881	12,006	2,126	21.5%
2046	9,985	11,998	2,013	20.2%

10. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4

a. Provide the estimated seasonal net firm peak demand, total available capacity and reserve margin for each year of the proposed project life, for each resource plan.

with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter]			
Scenario	With CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	9,406	12,933	3,528	37.5%
2021	8,789	12,889	4,101	46.7%
2022	9,167	12,465	3,298	36.0%
2023	8,922	12,465	3,543	39.7%
2024	9,012	12,350	3,339	37.0%
2025	8,777	12,068	3,291	37.5%
2026	8,880	11,726	2,846	32.0%
2027	8,941	11,726	2,785	31.1%
2028	9,003	10,809	1,806	20.1%
2029	9,038	10,809	1,771	19.6%
2030	9,091	11,049	1,958	21.5%
2031	9,036	10,818	1,782	19.7%
2032	9,222	11,057	1,835	19.9%
2033	9,249	11,057	1,808	19.6%
2034	9,316	11,297	1,981	21.3%
2035	9,379	11,251	1,871	19.9%
2036	9,075	11,251	2,176	24.0%
2037	9,109	11,102	1,993	21.9%
2038	9,173	11,102	1,930	21.0%
2039	9,236	11,198	1,963	21.2%
2040	9,338	11,198	1,860	19.9%
2041	9,358	11,438	2,079	22.2%
2042	9,336	11,438	2,102	22.5%
2043	9,491	11,790	2,299	24.2%
2044	9,594	11,790	2,196	22.9%
2045	9,606	12,108	2,502	26.0%
2046	9,673	12,062	2,389	24.7%

Season	[Summer]			
Scenario	With CEC Units			
Year	Net Firm Peak Demand (MW)	Total Capacity Available (MW)	Reserve Margin (MW)	Reserve Margin (%)
2020	8,915	11,934	3,019	33.9%
2021	8,946	11,553	2,607	29.1%
2022	9,007	11,754	2,747	30.5%
2023	8,735	11,922	3,187	36.5%
2024	8,769	11,831	3,062	34.9%
2025	8,588	11,712	3,124	36.4%
2026	8,612	11,433	2,821	32.8%
2027	8,666	10,684	2,018	23.3%
2028	8,759	10,636	1,877	21.4%
2029	8,829	10,858	2,028	23.0%
2030	8,904	10,654	1,749	19.6%
2031	8,940	10,876	1,936	21.7%
2032	9,031	10,872	1,841	20.4%
2033	9,102	11,094	1,992	21.9%
2034	9,191	11,110	1,919	20.9%
2035	9,283	11,106	1,824	19.6%
2036	8,984	11,016	2,032	22.6%
2037	9,067	11,012	1,945	21.5%
2038	9,220	11,146	1,927	20.9%
2039	9,294	11,142	1,848	19.9%
2040	9,405	11,364	1,959	20.8%
2041	9,494	11,361	1,867	19.7%
2042	9,570	11,631	2,061	21.5%
2043	9,679	11,627	1,949	20.1%
2044	9,985	11,935	1,950	19.5%
2045	9,881	11,937	2,057	20.8%
2046	9,985	12,153	2,168	21.7%

10. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4

b. Provide the annual change in each season's total capacity available caused by unit additions, retirements, and uprates/derates. Identify both the unit(s) and megawatts associated with each, for each year of the proposed project life, for each resource plan, with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter]			
Scenario	Without CEC Units			
Year	Unit Additions	Retirements	Uprates / Downrates	Annual Change in Capacity Available
2020	Columbia Solar			75
2020	DeBary Solar			75
2020		Avon Park 1-2		-50
2021	Santa Fe Solar			75
2021	Twin Rivers Solar			75
2021	Duette Solar			75
2021	Charlie Creek Solar			75
2021	Archer Solar			56
2021		Southern Contract Expiress		-424
2022				
2023				
2023		Orlando Contract Expires		-115
2024				
2024		Shady Hills Contract Expires		-522
2024			Osprey Transmission Upgrade	355
2024		Mulberry Contract Expires		-115
2025		Bayboro 1-4		-238
2025		Orange Contract Expires		-104
2027		DeBary 2-6		-324
2027		Bartow 1 and 3		-105
2027		Vandolah Contract Expires		-681
2027		UF		-46
2027	New CT			479
2028	New CT			240
2029				
2030		[redacted]		[redacted]
2030	New CT	[redacted]		240
2031		[redacted]		
2032	New CT	[redacted]		240
2033		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034	New CTs	[redacted]		958
2034	New CC	[redacted]		1,377
2036		[redacted]		
2036		[redacted]		[redacted]
2038		[redacted]		[redacted]
2038	New CTs	[redacted]		719
2040	New CT	[redacted]		240
2042		[redacted]		[redacted]
2042	New CC	[redacted]		1,377
2044		[redacted]		[redacted]
2044	New CTs	[redacted]		479
2045	New CT	[redacted]		240
2045		[redacted]		[redacted]
2046		[redacted]		

New CTs and New CCs are in service in June
All Solar Generation is reported as nameplate value.
Solar Capacity Degradation not included.

Season	[Summer]			
Scenario	Without CEC Units			
Year	Unit Additions	Retirements	Uprates / Downrates	Annual Change in Capacity Available
2020	Columbia Solar			75
2020	DeBary Solar			75
2020		Avon Park 1-2		-48
2021	Santa Fe Solar			75
2021	Twin Rivers Solar			75
2021	Duette Solar			75
2021	Charlie Creek Solar			75
2021	Archer Solar			56
2021		Southern Contract Expiress		-424
2022				
2023				
2023		Orlando Contract Expires		-115
2024				
2024		Shady Hills Contract Expires		-480
2024			Osprey Transmission Upgrade	337
2024		Mulberry Contract Expires		-115
2025		Bayboro 1-4		-171
2025		Orange Contract Expires		-104
2027		DeBary 2-6		-249
2027		Bartow 1 and 3		-82
2027		Vandolah Contract Expires		-640
2027		UF		-44
2027	New CT			452
2028	New CT			226
2029				
2030		[redacted]		[redacted]
2030	New CT	[redacted]		226
2031		[redacted]		
2032	New CT	[redacted]		226
2033		[redacted]		
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034	New CTs	[redacted]		903
2034	New CC	[redacted]		1,277
2036		[redacted]		
2036		[redacted]		[redacted]
2038		[redacted]		[redacted]
2038	New CTs	[redacted]		677
2040	New CT	[redacted]		226
2042		[redacted]		[redacted]
2042	New CC	[redacted]		1,277
2044		[redacted]		[redacted]
2044	New CTs	[redacted]		452
2045	New CT	[redacted]		226
2045		[redacted]		[redacted]
2046		[redacted]		

New CTs and New CCs are in service in June
All Solar Generation is reported as nameplate value.
Solar Capacity Degradation not included.

10. Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-4

b. Provide the annual change in each season's total capacity available caused by unit additions, retirements, and uprates/derates. Identify both the unit(s) and megawatts associated with each, for each year of the proposed project life, for each resource plan, with and without the CEC projects. As part of your response, complete the table below and provide in electronic (Excel) format.

Season	[Winter]			
Scenario	With CEC Units			
Year	Unit Additions	Retirements	Uprates / Downrates	Annual Change in Firm Capacity Available
2020	Columbia Solar			75
2020	DeBary Solar			75
2020		Avon Park 1-2		-50
2021	Santa Fe Solar			75
2021	Twin Rivers Solar			75
2021	Duette Solar			75
2021	Charlie Creek Solar			75
2021	Archer Solar			56
2021		Southern Contract Expiress		-424
2022	Clean Energy Connection			150
2023	Clean Energy Connection			300
2023		Orlando Contract Expires		-115
2024	Clean Energy Connection			300
2024		Shady Hills Contract Expires		-522
2024			Osprey Transmission Upgrade	355
2024		Mulberry Contract Expires		-115
2025		Bayboro 1-4		-238
2025		Orange Contract Expires		-104
2027		DeBary 2-6		-324
2027		Bartow 1 and 3		-105
2027		Vandolah Contract Expires		-681
2027		UF		-46
2027	New CT			240
2028				
2029	New CT			240
2030		[redacted]		[redacted]
2030		[redacted]		
2031	New CT	[redacted]		240
2032		[redacted]		
2033	New CT	[redacted]		240
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034	New CTs	[redacted]		719
2034	New CC	[redacted]		1,377
2036	New CT	[redacted]		240
2036		[redacted]		[redacted]
2038		[redacted]		[redacted]
2038	New CTs	[redacted]		479
2040	New CT	[redacted]		240
2042		[redacted]		[redacted]
2042	New CC	[redacted]		1,377
2044		[redacted]		[redacted]
2044	New CTs	[redacted]		479
2045	New CT	[redacted]		240
2045		[redacted]		[redacted]
2046	New CT	[redacted]		240

New CTs and New CCs are in service in June
All Solar Generation is reported as nameplate value.
Solar Capacity Degradation not included.

Season	[Summer]			
Scenario	With CEC Units			
Year	Unit Additions	Retirements	Uprates / Downrates	Annual Change in Firm Capacity Available
2020	Columbia Solar			75
2020	DeBary Solar			75
2020		Avon Park 1-2		-48
2021	Santa Fe Solar			75
2021	Twin Rivers Solar			75
2021	Duette Solar			75
2021	Charlie Creek Solar			75
2021	Archer Solar			56
2021		Southern Contract Expiress		-424
2022	Clean Energy Connection			150
2023	Clean Energy Connection			300
2023		Orlando Contract Expires		-115
2024	Clean Energy Connection			300
2024		Shady Hills Contract Expires		-480
2024			Osprey Transmission Upgrade	337
2024		Mulberry Contract Expires		-115
2025		Bayboro 1-4		-171
2025		Orange Contract Expires		-104
2027		DeBary 2-6		-249
2027		Bartow 1 and 3		-82
2027		Vandolah Contract Expires		-640
2027		UF		-44
2027	New CT			226
2028				
2029	New CT			226
2030		[redacted]		[redacted]
2030		[redacted]		
2031	New CT	[redacted]		226
2032		[redacted]		
2033	New CT	[redacted]		226
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034		[redacted]		[redacted]
2034	New CTs	[redacted]		677
2034	New CC	[redacted]		1,277
2036	New CT	[redacted]		226
2036		[redacted]		[redacted]
2038		[redacted]		[redacted]
2038	New CTs	[redacted]		452
2040	New CT	[redacted]		226
2042		[redacted]		[redacted]
2042	New CC	[redacted]		1,277
2044		[redacted]		[redacted]
2044	New CTs	[redacted]		452
2045	New CT	[redacted]		226
2045		[redacted]		[redacted]
2046	New CT	[redacted]		226

New CTs and New CCs are in service in June
All Solar Generation is reported as nameplate value.
Solar Capacity Degradation not included.

20FL-CEC-002050 - 20FL-CEC-002058

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in nominal and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed beMid. As a part of this response please complete the table beMid and provide in electronic (Excel) format for each scenario.

a. Mid Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Mid Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,655	751	171	10	12	2,751	-	2,751	-	2,751
2022	-	-	-	-	244	23	2,431	1,087	258	17	18	4,078	-	4,078	-	4,078
2023	-	-	-	-	338	33	3,173	1,401	346	24	23	5,338	-	5,338	-	5,338
2024	-	-	-	-	421	42	3,878	1,696	436	31	27	6,531	-	6,531	-	6,531
2025	-	-	-	-	494	50	4,581	1,972	530	37	32	7,695	74	7,769	-	7,769
2026	-	-	-	-	553	57	5,296	2,231	632	43	36	8,848	199	9,047	-	9,047
2027	-	-	-	-	618	65	6,050	2,474	741	50	40	10,037	369	10,406	-	10,406
2028	-	-	-	-	690	75	6,859	2,702	857	57	45	11,283	582	11,865	-	11,865
2029	-	-	-	-	759	85	7,683	2,915	973	63	49	12,526	830	13,356	-	13,356
2030	-	-	-	-	826	95	8,504	3,114	1,094	69	53	13,755	1,109	14,865	-	14,865
2031	-	-	-	-	891	104	9,310	3,301	1,218	75	57	14,957	1,406	16,363	-	16,363
2032	-	-	-	-	955	113	10,114	3,477	1,340	81	60	16,140	1,723	17,863	-	17,863
2033	-	-	-	-	1,015	122	10,874	3,641	1,463	87	63	17,265	2,053	19,318	-	19,318
2034	-	-	-	-	1,119	148	11,607	3,838	1,579	96	64	18,452	2,373	20,825	-	20,825
2035	-	-	-	-	1,245	288	12,318	4,052	1,694	106	65	19,769	2,694	22,463	-	22,463
2036	-	-	-	-	1,360	416	13,006	4,253	1,808	116	66	21,023	3,061	24,084	-	24,084
2037	-	-	-	-	1,464	532	13,703	4,440	1,928	125	66	22,259	3,466	25,725	-	25,725
2038	-	-	-	-	1,571	640	14,395	4,630	2,047	134	67	23,483	3,905	27,388	-	27,388
2039	-	-	-	-	1,676	740	15,067	4,816	2,170	144	67	24,679	4,375	29,054	-	29,054
2040	-	-	-	-	1,774	832	15,730	4,995	2,287	153	68	25,839	4,869	30,708	-	30,708
2041	-	-	-	-	1,865	916	16,382	5,165	2,404	162	68	26,962	5,385	32,347	-	32,347
2042	-	-	-	-	1,968	1,002	17,006	5,343	2,516	173	69	28,076	5,904	33,981	-	33,981
2043	-	-	-	-	2,075	1,155	17,606	5,523	2,625	183	69	29,235	6,432	35,667	-	35,667
2044	-	-	-	-	2,177	1,295	18,197	5,698	2,730	194	69	30,360	6,972	37,332	-	37,332
2045	-	-	-	-	2,277	1,423	18,786	5,870	2,835	204	70	31,465	7,518	38,984	-	38,984
2046	-	-	-	-	2,368	1,541	19,367	6,033	2,936	215	70	32,530	8,071	40,601	-	40,601
2047	-	-	-	-	2,452	1,647	19,918	6,187	3,035	225	71	33,534	8,620	42,155	-	42,155
2048	-	-	-	-	2,527	1,744	20,457	6,330	3,131	234	71	34,495	9,169	43,664	-	43,664
2049	-	-	-	-	2,596	1,832	20,968	6,465	3,225	243	71	35,400	9,709	45,109	-	45,109
2050	-	-	-	-	2,657	1,912	21,459	6,591	3,316	250	71	36,257	10,248	46,505	-	46,505
2051	-	-	-	-	2,711	1,984	21,935	6,710	3,405	257	72	37,073	10,784	47,857	-	47,857
2052	-	-	-	-	2,758	2,049	22,396	6,820	3,490	263	72	37,849	11,314	49,163	-	49,163
2053	-	-	-	-	2,802	2,108	22,837	6,924	3,573	269	72	38,585	11,831	50,416	-	50,416
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
								OK	OK		OK		OK			

Mid Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,655	751	171	10	12	2,751	-	2,751	1	2,752
2022	24	2	1	27	244	23	2,424	1,087	257	17	18	4,097	-	4,097	2	4,098
2023	86	9	4	99	338	33	3,146	1,401	342	24	22	5,405	-	5,405	2	5,407
2024	178	18	9	205	421	42	3,813	1,696	428	31	27	6,663	-	6,663	3	6,666
2025	260	27	14	300	494	50	4,481	1,972	518	37	31	7,884	71	7,954	3	7,957
2026	332	35	18	385	553	57	5,161	2,231	617	43	35	9,083	190	9,273	3	9,277
2027	392	42	23	457	612	64	5,879	2,474	723	50	39	10,297	353	10,650	4	10,653
2028	446	49	27	521	669	72	6,654	2,702	835	56	44	11,553	557	12,110	4	12,114
2029	494	55	31	580	726	80	7,441	2,915	948	62	48	12,800	794	13,594	4	13,599
2030	538	60	35	634	782	87	8,229	3,114	1,066	68	52	14,032	1,064	15,096	5	15,101
2031	579	65	39	683	837	95	8,999	3,301	1,187	74	56	15,232	1,350	16,582	5	16,587
2032	615	70	43	728	890	102	9,770	3,477	1,306	79	59	16,413	1,655	18,068	5	18,073
2033	649	74	47	770	943	110	10,498	3,641	1,426	85	62	17,535	1,973	19,508	5	19,513
2034	679	78	50	807	1,037	134	11,200	3,828	1,540	93	63	18,703	2,280	20,983	5	20,988
2035	707	81	54	842	1,151	272	11,882	4,025	1,653	102	64	19,990	2,588	22,578	6	22,584
2036	732	84	57	873	1,260	398	12,541	4,215	1,765	111	64	21,227	2,940	24,167	6	24,173
2037	755	87	60	902	1,361	514	13,209	4,395	1,883	120	65	22,450	3,329	25,778	6	25,784
2038	778	90	63	930	1,460	621	13,873	4,574	2,000	129	66	23,653	3,749	27,402	6	27,408
2039	798	92	66	956	1,556	719	14,517	4,747	2,121	138	66	24,820	4,200	29,021	6	29,027
2040	817	94	68	979	1,647	809	15,153	4,913	2,237	146	67	25,951	4,674	30,626	6	30,632
2041	833	96	71	1,000	1,731	892	15,779	5,072	2,352	155	67	27,048	5,169	32,217	6	32,223
2042	848	98	73	1,019	1,828	977	16,379	5,239	2,462	164	67	28,136	5,669	33,805	6	33,811
2043	862	99	76	1,037	1,929	1,129	16,955	5,408	2,569	174	68	29,268	6,176	35,444	7	35,451
2044	874	101	78	1,052	2,026	1,268	17,524	5,574	2,673	184	68	30,370	6,696	37,066	7	37,072
2045	884	102	80	1,067	2,120	1,395	18,092	5,737	2,776	194	69	31,451	7,222	38,673	7	38,679
2046	894	103	82	1,080	2,210	1,512	18,651	5,895	2,876	204	69	32,498	7,755	40,253	7	40,260
2047	903	104	84	1,092	2,293	1,619	19,183	6,046	2,975	214	69	33,491	8,286	41,776	7	41,783
2048	911	105	86	1,103	2,369	1,716	19,702	6,187	3,070	223	70	34,438	8,814	43,252	7	43,259
2049	918	106	88	1,112	2,437	1,803	20,196	6,319	3,162	232	70	35,332	9,336	44,668	7	44,675
2050	924	107	90	1,121	2,498	1,883	20,670	6,443	3,252	239	70	36,176	9,857	46,033	7	46,040
2051	930	108	92	1,130	2,552	1,955	21,128	6,559	3,342	246	70	36,983	10,373	47,355	7	47,363
2052	935	109	93	1,137	2,600	2,020	21,576	6,668	3,426	251	71	37,749	10,888	48,637	7	48,644
2053	938	109	94	1,140	2,643	2,079	22,010	6,770	3,509	257	71	38,479	11,396	49,875	7	49,883
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Mid Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(7)	-	(1)	(0)	(0)	19	-	19	2	20	2022
2023	86	9	4	99	-	-	(27)	-	(4)	0	(0)	67	-	67	2	69	2023
2024	178	18	9	205	-	-	(65)	-	(9)	0	(0)	132	-	132	3	135	2024
2025	260	27	14	300	-	-	(100)	-	(12)	0	(1)	188	(3)	185	3	188	2025
2026	332	35	18	385	-	-	(135)	-	(15)	0	(1)	235	(9)	226	3	229	2026
2027	392	42	23	457	(6)	(1)	(171)	-	(18)	(0)	(1)	260	(16)	244	4	248	2027
2028	446	49	27	521	(21)	(3)	(205)	-	(22)	(1)	(1)	269	(24)	245	4	249	2028
2029	494	55	31	580	(32)	(5)	(242)	-	(25)	(1)	(1)	273	(35)	238	4	242	2029
2030	538	60	35	634	(45)	(7)	(275)	-	(28)	(1)	(1)	277	(45)	232	5	236	2030
2031	579	65	39	683	(54)	(9)	(311)	-	(31)	(2)	(1)	275	(56)	219	5	224	2031
2032	615	70	43	728	(64)	(11)	(344)	-	(34)	(2)	(1)	272	(67)	205	5	210	2032
2033	649	74	47	770	(72)	(12)	(376)	-	(36)	(2)	(1)	270	(79)	191	5	196	2033
2034	679	78	50	807	(82)	(14)	(408)	(10)	(39)	(3)	(1)	251	(93)	158	5	163	2034
2035	707	81	54	842	(94)	(16)	(437)	(27)	(42)	(4)	(1)	221	(106)	115	6	121	2035
2036	732	84	57	873	(100)	(17)	(465)	(38)	(44)	(4)	(1)	204	(121)	83	6	89	2036
2037	755	87	60	902	(104)	(18)	(494)	(45)	(44)	(5)	(1)	191	(137)	53	6	59	2037
2038	778	90	63	930	(111)	(19)	(522)	(56)	(47)	(5)	(1)	169	(155)	14	6	20	2038
2039	798	92	66	956	(119)	(21)	(550)	(69)	(48)	(6)	(1)	141	(175)	(34)	6	(28)	2039
2040	817	94	68	979	(127)	(22)	(577)	(82)	(50)	(7)	(1)	113	(195)	(82)	6	(76)	2040
2041	833	96	71	1,000	(134)	(24)	(603)	(93)	(52)	(8)	(1)	85	(216)	(130)	6	(124)	2041
2042	848	98	73	1,019	(140)	(25)	(627)	(104)	(54)	(8)	(1)	60	(236)	(176)	6	(170)	2042
2043	862	99	76	1,037	(146)	(26)	(651)	(114)	(55)	(9)	(1)	34	(256)	(223)	7	(216)	2043
2044	874	101	78	1,052	(151)	(27)	(673)	(124)	(57)	(9)	(1)	10	(276)	(266)	7	(260)	2044
2045	884	102	80	1,067	(156)	(28)	(695)	(133)	(58)	(10)	(1)	(15)	(296)	(311)	7	(304)	2045
2046	894	103	82	1,080	(158)	(29)	(716)	(138)	(60)	(10)	(1)	(32)	(316)	(348)	7	(341)	2046
2047	903	104	84	1,092	(158)	(29)	(735)	(141)	(61)	(11)	(1)	(43)	(335)	(378)	7	(371)	2047
2048	911	105	86	1,103	(158)	(29)	(755)	(143)	(62)	(11)	(1)	(57)	(355)	(412)	7	(405)	2048
2049	918	106	88	1,112	(158)	(29)	(773)	(146)	(63)	(11)	(1)	(68)	(373)	(442)	7	(435)	2049
2050	924	107	90	1,121	(158)	(29)	(790)	(148)	(64)	(11)	(1)	(80)	(392)	(472)	7	(465)	2050
2051	930	108	92	1,130	(159)	(29)	(807)	(150)	(63)	(12)	(1)	(90)	(411)	(501)	7	(494)	2051
2052	935	109	93	1,137	(159)	(29)	(820)	(152)	(64)	(12)	(1)	(100)	(426)	(527)	7	(519)	2052
2053	938	109	94	1,140	(159)	(29)	(827)	(154)	(65)	(12)	(1)	(106)	(434)	(540)	7	(533)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRRRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in CPVRR and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed beHIgh. As a part of this response please complete the table beHIgh and provide in electronic (Excel) format for each scenario.

a. HIgh Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

HIgh Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,662	751	172	10	12	2,758	-	2,758	-	2,758
2022	-	-	-	-	244	23	2,494	1,087	258	17	19	4,142	-	4,142	-	4,142
2023	-	-	-	-	338	33	3,365	1,401	345	24	27	5,532	-	5,532	-	5,532
2024	-	-	-	-	421	42	4,277	1,696	431	31	37	6,935	-	6,935	-	6,935
2025	-	-	-	-	494	50	5,197	1,972	524	37	45	8,318	81	8,400	-	8,400
2026	-	-	-	-	553	57	6,144	2,231	624	43	52	9,705	217	9,921	-	9,921
2027	-	-	-	-	618	65	7,128	2,474	732	50	58	11,124	396	11,519	-	11,519
2028	-	-	-	-	690	75	8,162	2,702	847	57	63	12,595	617	13,212	-	13,212
2029	-	-	-	-	759	85	9,204	2,915	962	63	69	14,057	875	14,931	-	14,931
2030	-	-	-	-	826	95	10,243	3,114	1,083	69	74	15,504	1,164	16,668	-	16,668
2031	-	-	-	-	891	104	11,277	3,301	1,206	75	79	16,934	1,471	18,405	-	18,405
2032	-	-	-	-	955	113	12,303	3,477	1,328	81	83	18,340	1,798	20,138	-	20,138
2033	-	-	-	-	1,015	122	13,273	3,641	1,449	87	87	19,675	2,141	21,816	-	21,816
2034	-	-	-	-	1,119	148	14,251	3,838	1,566	96	89	21,107	2,468	23,575	-	23,575
2035	-	-	-	-	1,245	288	15,216	4,052	1,682	106	90	22,679	2,789	25,468	-	25,468
2036	-	-	-	-	1,360	416	16,147	4,253	1,796	116	90	24,178	3,156	27,333	-	27,333
2037	-	-	-	-	1,464	532	17,102	4,440	1,917	125	91	25,671	3,561	29,232	-	29,232
2038	-	-	-	-	1,571	640	18,059	4,630	2,037	134	91	27,162	3,999	31,161	-	31,161
2039	-	-	-	-	1,676	740	18,983	4,816	2,161	144	92	28,612	4,470	33,081	-	33,081
2040	-	-	-	-	1,774	832	19,911	4,995	2,279	153	92	30,037	4,963	35,000	-	35,000
2041	-	-	-	-	1,865	916	20,832	5,165	2,398	162	93	31,431	5,479	36,910	-	36,910
2042	-	-	-	-	1,968	1,002	21,721	5,343	2,510	173	93	32,810	5,998	38,808	-	38,808
2043	-	-	-	-	2,075	1,155	22,583	5,523	2,620	183	94	34,232	6,526	40,758	-	40,758
2044	-	-	-	-	2,177	1,295	23,417	5,698	2,726	194	94	35,601	7,066	42,667	-	42,667
2045	-	-	-	-	2,277	1,423	24,248	5,870	2,831	204	95	36,948	7,612	44,560	-	44,560
2046	-	-	-	-	2,368	1,541	25,077	6,033	2,933	215	95	38,262	8,165	46,427	-	46,427
2047	-	-	-	-	2,452	1,647	25,880	6,187	3,033	225	95	39,519	8,714	48,233	-	48,233
2048	-	-	-	-	2,527	1,744	26,669	6,330	3,130	234	96	40,731	9,263	49,993	-	49,993
2049	-	-	-	-	2,596	1,832	27,419	6,465	3,225	243	96	41,875	9,803	51,678	-	51,678
2050	-	-	-	-	2,657	1,912	28,148	6,591	3,316	250	96	42,970	10,342	53,312	-	53,312
2051	-	-	-	-	2,711	1,984	28,854	6,710	3,406	257	96	44,018	10,877	54,895	-	54,895
2052	-	-	-	-	2,758	2,049	29,539	6,820	3,492	263	97	45,018	11,408	56,426	-	56,426
2053	-	-	-	-	2,802	2,108	30,192	6,924	3,576	269	97	45,968	11,924	57,892	-	57,892
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,662	751	172	10	12	2,758	-	2,758	1	2,759
2022	24	2	1	27	244	23	2,486	1,087	257	17	19	4,160	-	4,160	2	4,162
2023	86	9	4	99	338	33	3,334	1,401	340	24	26	5,594	-	5,594	2	5,597
2024	178	18	9	205	421	42	4,199	1,696	423	31	36	7,053	-	7,053	3	7,056
2025	260	27	14	300	494	50	5,073	1,972	513	37	44	8,483	78	8,561	3	8,564
2026	332	35	18	385	553	57	5,975	2,231	610	43	50	9,906	207	10,113	3	10,116
2027	392	42	23	457	612	64	6,913	2,474	714	50	56	11,340	378	11,718	4	11,722
2028	446	49	27	521	669	72	7,904	2,702	825	56	62	12,811	590	13,402	4	13,406
2029	494	55	31	580	726	80	8,901	2,915	938	62	67	14,269	836	15,105	4	15,109
2030	538	60	35	634	782	87	9,899	3,114	1,055	68	72	15,712	1,113	16,825	5	16,830
2031	579	65	39	683	837	95	10,887	3,301	1,176	74	76	17,130	1,407	18,537	5	18,542
2032	615	70	43	728	890	102	11,872	3,477	1,295	79	81	18,524	1,720	20,245	5	20,250
2033	649	74	47	770	943	110	12,801	3,641	1,414	85	84	19,848	2,050	21,898	5	21,903
2034	679	78	50	807	1,037	134	13,736	3,828	1,528	93	86	21,249	2,364	23,613	5	23,618
2035	707	81	54	842	1,151	272	14,661	4,025	1,641	102	87	22,781	2,671	25,453	6	25,458
2036	732	84	57	873	1,260	398	15,554	4,215	1,754	111	87	24,252	3,023	27,275	6	27,281
2037	755	87	60	902	1,361	514	16,469	4,395	1,873	120	88	25,723	3,411	29,134	6	29,140
2038	778	90	63	930	1,460	621	17,386	4,574	1,991	129	88	27,180	3,832	31,012	6	31,018
2039	798	92	66	956	1,556	719	18,273	4,747	2,113	138	89	28,591	4,283	32,874	6	32,880
2040	817	94	68	979	1,647	809	19,163	4,913	2,230	146	89	29,977	4,757	34,733	6	34,740
2041	833	96	71	1,000	1,731	892	20,046	5,072	2,346	155	90	31,332	5,251	36,583	6	36,589
2042	848	98	73	1,019	1,828	977	20,900	5,239	2,457	164	90	32,674	5,751	38,425	6	38,432
2043	862	99	76	1,037	1,929	1,129	21,728	5,408	2,565	174	91	34,060	6,258	40,318	7	40,324
2044	874	101	78	1,052	2,026	1,268	22,531	5,574	2,670	184	91	35,396	6,778	42,174	7	42,180
2045	884	102	80	1,067	2,120	1,395	23,330	5,737	2,774	194	91	36,709	7,304	44,013	7	44,020
2046	894	103	82	1,080	2,210	1,512	24,129	5,895	2,874	204	92	37,997	7,837	45,834	7	45,841
2047	903	104	84	1,092	2,293	1,619	24,904	6,046	2,973	214	92	39,233	8,367	47,601	7	47,608
2048	911	105	86	1,103	2,369	1,716	25,663	6,187	3,069	223	92	40,422	8,896	49,318	7	49,325
2049	918	106	88	1,112	2,437	1,803	26,387	6,319	3,163	232	93	41,547	9,417	50,964	7	50,972
2050	924	107	90	1,121	2,498	1,883	27,091	6,443	3,253	239	93	42,622	9,938	52,560	7	52,567
2051	930	108	92	1,130	2,552	1,955	27,772	6,559	3,344	246	93	43,651	10,454	54,105	7	54,113
2052	935	109	93	1,137	2,600	2,020	28,436	6,668	3,429	251	94	44,634	10,969	55,604	7	55,611
2053	938	109	94	1,140	2,643	2,079	29,080	6,770	3,512	257	94	45,575	11,478	57,053	7	57,060
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(8)	-	(1)	(0)	(0)	18	-	18	2	20	2022
2023	86	9	4	99	-	-	(31)	-	(4)	0	(0)	63	-	63	2	65	2023
2024	178	18	9	205	-	-	(79)	-	(8)	0	(1)	118	-	118	3	121	2024
2025	260	27	14	300	-	-	(124)	-	(11)	0	(1)	165	(4)	161	3	164	2025
2026	332	35	18	385	-	-	(169)	-	(14)	0	(1)	201	(9)	191	3	195	2026
2027	392	42	23	457	(6)	(1)	(215)	-	(18)	(0)	(2)	216	(17)	199	4	203	2027
2028	446	49	27	521	(21)	(3)	(257)	-	(21)	(1)	(2)	216	(27)	190	4	194	2028
2029	494	55	31	580	(32)	(5)	(303)	-	(24)	(1)	(2)	212	(38)	174	4	178	2029
2030	538	60	35	634	(45)	(7)	(343)	-	(27)	(1)	(2)	207	(51)	157	5	162	2030
2031	579	65	39	683	(54)	(9)	(389)	-	(30)	(2)	(3)	196	(65)	132	5	137	2031
2032	615	70	43	728	(64)	(11)	(432)	-	(33)	(2)	(3)	184	(78)	107	5	112	2032
2033	649	74	47	770	(72)	(12)	(472)	-	(35)	(2)	(3)	173	(91)	82	5	87	2033
2034	679	78	50	807	(82)	(14)	(515)	(10)	(38)	(3)	(3)	143	(105)	38	5	44	2034
2035	707	81	54	842	(94)	(16)	(555)	(27)	(41)	(4)	(3)	103	(118)	(15)	6	(10)	2035
2036	732	84	57	873	(100)	(17)	(593)	(38)	(42)	(4)	(3)	75	(133)	(58)	6	(52)	2036
2037	755	87	60	902	(104)	(18)	(633)	(45)	(43)	(5)	(3)	51	(149)	(98)	6	(92)	2037
2038	778	90	63	930	(111)	(19)	(672)	(56)	(46)	(5)	(3)	18	(167)	(149)	6	(143)	2038
2039	798	92	66	956	(119)	(21)	(710)	(69)	(48)	(6)	(3)	(21)	(187)	(207)	6	(201)	2039
2040	817	94	68	979	(127)	(22)	(749)	(82)	(50)	(7)	(3)	(60)	(207)	(267)	6	(261)	2040
2041	833	96	71	1,000	(134)	(24)	(786)	(93)	(51)	(8)	(3)	(99)	(227)	(327)	6	(320)	2041
2042	848	98	73	1,019	(140)	(25)	(821)	(104)	(53)	(8)	(3)	(136)	(248)	(383)	6	(377)	2042
2043	862	99	76	1,037	(146)	(26)	(855)	(114)	(55)	(9)	(3)	(172)	(268)	(440)	7	(434)	2043
2044	874	101	78	1,052	(151)	(27)	(887)	(124)	(56)	(9)	(3)	(205)	(288)	(493)	7	(487)	2044
2045	884	102	80	1,067	(156)	(28)	(918)	(133)	(58)	(10)	(3)	(239)	(308)	(547)	7	(540)	2045
2046	894	103	82	1,080	(158)	(29)	(948)	(138)	(59)	(10)	(3)	(265)	(328)	(593)	7	(586)	2046
2047	903	104	84	1,092	(158)	(29)	(976)	(141)	(60)	(11)	(3)	(286)	(347)	(632)	7	(625)	2047
2048	911	105	86	1,103	(158)	(29)	(1,005)	(143)	(61)	(11)	(3)	(308)	(367)	(675)	7	(668)	2048
2049	918	106	88	1,112	(158)	(29)	(1,031)	(146)	(62)	(11)	(3)	(328)	(385)	(714)	7	(707)	2049
2050	924	107	90	1,121	(158)	(29)	(1,057)	(148)	(63)	(11)	(3)	(348)	(404)	(752)	7	(745)	2050
2051	930	108	92	1,130	(159)	(29)	(1,082)	(150)	(62)	(12)	(3)	(367)	(423)	(790)	7	(783)	2051
2052	935	109	93	1,137	(159)	(29)	(1,103)	(152)	(63)	(12)	(3)	(384)	(438)	(822)	7	(815)	2052
2053	938	109	94	1,140	(159)	(29)	(1,113)	(154)	(64)	(12)	(3)	(393)	(446)	(839)	7	(831)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in CPVRR and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed below. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Low Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,655	751	171	10	12	2,751	-	2,751	-	2,751
2022	-	-	-	-	244	23	2,431	1,087	258	17	18	4,078	-	4,078	-	4,078
2023	-	-	-	-	338	33	3,173	1,401	346	24	23	5,338	-	5,338	-	5,338
2024	-	-	-	-	421	42	3,870	1,696	436	31	27	6,522	-	6,522	-	6,522
2025	-	-	-	-	494	50	4,546	1,972	529	37	31	7,660	74	7,734	-	7,734
2026	-	-	-	-	553	57	5,222	2,231	632	43	35	8,773	197	8,970	-	8,970
2027	-	-	-	-	618	65	5,921	2,474	741	50	39	9,908	365	10,273	-	10,273
2028	-	-	-	-	690	75	6,648	2,702	857	57	43	11,071	575	11,646	-	11,646
2029	-	-	-	-	759	85	7,378	2,915	974	63	46	12,220	816	13,036	-	13,036
2030	-	-	-	-	826	95	8,101	3,114	1,097	69	50	13,352	1,088	14,440	-	14,440
2031	-	-	-	-	891	104	8,817	3,301	1,221	75	53	14,463	1,379	15,842	-	15,842
2032	-	-	-	-	955	113	9,513	3,477	1,344	81	55	15,539	1,689	17,228	-	17,228
2033	-	-	-	-	1,015	122	10,169	3,641	1,467	87	58	16,559	2,016	18,575	-	18,575
2034	-	-	-	-	1,119	148	10,787	3,838	1,584	96	59	17,630	2,336	19,966	-	19,966
2035	-	-	-	-	1,245	288	11,383	4,052	1,698	106	59	18,832	2,657	21,489	-	21,489
2036	-	-	-	-	1,360	416	11,950	4,253	1,812	116	60	19,966	3,024	22,990	-	22,990
2037	-	-	-	-	1,464	532	12,524	4,440	1,931	125	61	21,077	3,429	24,506	-	24,506
2038	-	-	-	-	1,571	640	13,091	4,630	2,049	134	61	22,176	3,868	26,044	-	26,044
2039	-	-	-	-	1,676	740	13,640	4,816	2,172	144	62	23,250	4,339	27,588	-	27,588
2040	-	-	-	-	1,774	832	14,176	4,995	2,289	153	62	24,281	4,833	29,113	-	29,113
2041	-	-	-	-	1,865	916	14,704	5,165	2,405	162	63	25,280	5,348	30,628	-	30,628
2042	-	-	-	-	1,968	1,002	15,205	5,343	2,516	173	63	26,270	5,868	32,138	-	32,138
2043	-	-	-	-	2,075	1,155	15,681	5,523	2,625	183	64	27,306	6,396	33,701	-	33,701
2044	-	-	-	-	2,177	1,295	16,150	5,698	2,730	194	64	28,307	6,936	35,243	-	35,243
2045	-	-	-	-	2,277	1,423	16,612	5,870	2,834	204	64	29,285	7,482	36,767	-	36,767
2046	-	-	-	-	2,368	1,541	17,066	6,033	2,935	215	65	30,223	8,035	38,258	-	38,258
2047	-	-	-	-	2,452	1,647	17,496	6,187	3,034	225	65	31,105	8,584	39,690	-	39,690
2048	-	-	-	-	2,527	1,744	17,909	6,330	3,130	234	65	31,941	9,133	41,074	-	41,074
2049	-	-	-	-	2,596	1,832	18,296	6,465	3,223	243	66	32,720	9,673	42,393	-	42,393
2050	-	-	-	-	2,657	1,912	18,665	6,591	3,313	250	66	33,455	10,212	43,667	-	43,667
2051	-	-	-	-	2,711	1,984	19,024	6,710	3,402	257	66	34,154	10,748	44,902	-	44,902
2052	-	-	-	-	2,758	2,049	19,371	6,820	3,487	263	67	34,816	11,278	46,094	-	46,094
2053	-	-	-	-	2,802	2,108	19,703	6,924	3,570	269	67	35,442	11,795	47,237	-	47,237
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	139	12	1,655	751	171	10	12	2,751	-	2,751	1	2,752
2022	24	2	1	27	244	23	2,424	1,087	257	17	18	4,097	-	4,097	2	4,098
2023	86	9	4	99	338	33	3,146	1,401	342	24	22	5,405	-	5,405	2	5,407
2024	178	18	9	205	421	42	3,805	1,696	428	31	27	6,655	-	6,655	3	6,658
2025	260	27	14	300	494	50	4,448	1,972	517	37	31	7,850	70	7,920	3	7,923
2026	332	35	18	385	553	57	5,090	2,231	617	43	35	9,011	189	9,200	3	9,203
2027	392	42	23	457	612	64	5,756	2,474	723	50	38	10,173	350	10,523	4	10,527
2028	446	49	27	521	669	72	6,453	2,702	835	56	42	11,350	552	11,901	4	11,905
2029	494	55	31	580	726	80	7,150	2,915	949	62	46	12,507	784	13,292	4	13,296
2030	538	60	35	634	782	87	7,845	3,114	1,067	68	49	13,646	1,047	14,693	5	14,698
2031	579	65	39	683	837	95	8,529	3,301	1,189	74	52	14,760	1,328	16,089	5	16,094
2032	615	70	43	728	890	102	9,197	3,477	1,308	79	55	15,838	1,628	17,467	5	17,472
2033	649	74	47	770	943	110	9,826	3,641	1,429	85	58	16,861	1,943	18,804	5	18,809
2034	679	78	50	807	1,037	134	10,417	3,828	1,543	93	59	17,918	2,249	20,166	5	20,172
2035	707	81	54	842	1,151	272	10,989	4,025	1,654	102	59	19,095	2,557	21,652	6	21,657
2036	732	84	57	873	1,260	398	11,533	4,215	1,766	111	60	20,216	2,909	23,125	6	23,131
2037	755	87	60	902	1,361	514	12,083	4,395	1,884	120	60	21,320	3,297	24,617	6	24,623
2038	778	90	63	930	1,460	621	12,627	4,574	2,000	129	61	22,403	3,718	26,121	6	26,127
2039	798	92	66	956	1,556	719	13,155	4,747	2,121	138	61	23,454	4,169	27,623	6	27,629
2040	817	94	68	979	1,647	809	13,668	4,913	2,237	146	62	24,462	4,643	29,105	6	29,111
2041	833	96	71	1,000	1,731	892	14,175	5,072	2,351	155	62	25,439	5,138	30,577	6	30,583
2042	848	98	73	1,019	1,828	977	14,657	5,239	2,461	164	63	26,408	5,638	32,046	6	32,052
2043	862	99	76	1,037	1,929	1,129	15,115	5,408	2,568	174	63	27,422	6,145	33,567	7	33,573
2044	874	101	78	1,052	2,026	1,268	15,565	5,574	2,671	184	64	28,405	6,665	35,070	7	35,076
2045	884	102	80	1,067	2,120	1,395	16,011	5,737	2,774	194	64	29,363	7,191	36,554	7	36,561
2046	894	103	82	1,080	2,210	1,512	16,448	5,895	2,873	204	64	30,288	7,725	38,013	7	38,019
2047	903	104	84	1,092	2,293	1,619	16,863	6,046	2,971	214	65	31,163	8,255	39,418	7	39,425
2048	911	105	86	1,103	2,369	1,716	17,262	6,187	3,066	223	65	31,990	8,783	40,773	7	40,780
2049	918	106	88	1,112	2,437	1,803	17,635	6,319	3,158	232	65	32,762	9,305	42,067	7	42,074
2050	924	107	90	1,121	2,498	1,883	17,992	6,443	3,247	239	66	33,489	9,826	43,315	7	43,322
2051	930	108	92	1,130	2,552	1,955	18,337	6,559	3,337	246	66	34,182	10,342	44,524	7	44,531
2052	935	109	93	1,137	2,600	2,020	18,674	6,668	3,421	251	66	34,837	10,857	45,694	7	45,702
2053	938	109	94	1,140	2,643	2,079	19,001	6,770	3,503	257	66	35,460	11,366	46,826	7	46,833
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

CPVRR $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(7)	-	(1)	(0)	(0)	19	-	19	2	20	2022
2023	86	9	4	99	-	-	(27)	-	(4)	0	(0)	67	-	67	2	69	2023
2024	178	18	9	205	-	-	(64)	-	(8)	0	(0)	133	-	133	3	135	2024
2025	260	27	14	300	-	-	(98)	-	(12)	0	(1)	190	(3)	187	3	190	2025
2026	332	35	18	385	-	-	(132)	-	(15)	0	(1)	238	(9)	229	3	233	2026
2027	392	42	23	457	(6)	(1)	(165)	-	(18)	(0)	(1)	266	(15)	250	4	254	2027
2028	446	49	27	521	(21)	(3)	(195)	-	(22)	(1)	(1)	279	(23)	256	4	260	2028
2029	494	55	31	580	(32)	(5)	(229)	-	(26)	(1)	(1)	287	(32)	255	4	260	2029
2030	538	60	35	634	(45)	(7)	(257)	-	(29)	(1)	(0)	294	(40)	254	5	259	2030
2031	579	65	39	683	(54)	(9)	(288)	-	(32)	(2)	(0)	298	(50)	247	5	252	2031
2032	615	70	43	728	(64)	(11)	(316)	-	(36)	(2)	(0)	300	(61)	238	5	243	2032
2033	649	74	47	770	(72)	(12)	(342)	-	(38)	(2)	(0)	302	(73)	229	5	234	2033
2034	679	78	50	807	(82)	(14)	(369)	(10)	(41)	(3)	(0)	288	(87)	200	5	206	2034
2035	707	81	54	842	(94)	(16)	(394)	(27)	(44)	(4)	(0)	263	(101)	163	6	168	2035
2036	732	84	57	873	(100)	(17)	(417)	(38)	(46)	(4)	(0)	251	(115)	135	6	141	2036
2037	755	87	60	902	(104)	(18)	(440)	(45)	(46)	(5)	(0)	243	(132)	111	6	117	2037
2038	778	90	63	930	(111)	(19)	(463)	(56)	(48)	(5)	(0)	227	(150)	77	6	83	2038
2039	798	92	66	956	(119)	(21)	(486)	(69)	(50)	(6)	(0)	204	(169)	35	6	41	2039
2040	817	94	68	979	(127)	(22)	(508)	(82)	(52)	(7)	(0)	181	(189)	(8)	6	(2)	2040
2041	833	96	71	1,000	(134)	(24)	(529)	(93)	(54)	(8)	(0)	159	(210)	(51)	6	(45)	2041
2042	848	98	73	1,019	(140)	(25)	(548)	(104)	(56)	(8)	(0)	138	(230)	(93)	6	(86)	2042
2043	862	99	76	1,037	(146)	(26)	(567)	(114)	(57)	(9)	(0)	117	(251)	(134)	7	(128)	2043
2044	874	101	78	1,052	(151)	(27)	(584)	(124)	(59)	(9)	(0)	97	(271)	(173)	7	(167)	2044
2045	884	102	80	1,067	(156)	(28)	(601)	(133)	(60)	(10)	(0)	78	(291)	(213)	7	(207)	2045
2046	894	103	82	1,080	(158)	(29)	(618)	(138)	(62)	(10)	(0)	65	(311)	(246)	7	(239)	2046
2047	903	104	84	1,092	(158)	(29)	(633)	(141)	(63)	(11)	(0)	58	(330)	(272)	7	(265)	2047
2048	911	105	86	1,103	(158)	(29)	(648)	(143)	(64)	(11)	(0)	49	(350)	(301)	7	(294)	2048
2049	918	106	88	1,112	(158)	(29)	(661)	(146)	(65)	(11)	(0)	42	(368)	(326)	7	(319)	2049
2050	924	107	90	1,121	(158)	(29)	(674)	(148)	(66)	(11)	(0)	34	(386)	(352)	7	(345)	2050
2051	930	108	92	1,130	(159)	(29)	(687)	(150)	(65)	(12)	(0)	28	(406)	(377)	7	(370)	2051
2052	935	109	93	1,137	(159)	(29)	(697)	(152)	(66)	(12)	(0)	22	(421)	(399)	7	(392)	2052
2053	938	109	94	1,140	(159)	(29)	(702)	(154)	(67)	(12)	(0)	18	(429)	(411)	7	(404)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

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a. Mid Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Mid Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	805	361	85	6	6	1,353	-	1,353	-	1,353
2022	-	-	-	-	105	11	776	335	87	7	6	1,327	-	1,327	-	1,327
2023	-	-	-	-	94	10	742	314	88	7	5	1,259	-	1,259	-	1,259
2024	-	-	-	-	84	9	704	295	90	7	4	1,194	-	1,194	-	1,194
2025	-	-	-	-	73	8	703	276	94	7	5	1,164	74	1,238	-	1,238
2026	-	-	-	-	59	7	715	259	102	6	4	1,153	125	1,278	-	1,278
2027	-	-	-	-	65	9	754	242	109	6	4	1,189	170	1,359	-	1,359
2028	-	-	-	-	72	10	810	228	116	7	4	1,246	213	1,459	-	1,459
2029	-	-	-	-	69	10	824	213	116	6	4	1,243	248	1,491	-	1,491
2030	-	-	-	-	68	10	820	200	121	6	4	1,229	279	1,508	-	1,508
2031	-	-	-	-	65	9	806	187	124	6	4	1,201	297	1,498	-	1,498
2032	-	-	-	-	63	9	804	176	122	6	3	1,183	317	1,500	-	1,500
2033	-	-	-	-	60	9	760	164	122	6	3	1,125	330	1,455	-	1,455
2034	-	-	-	-	104	26	733	197	117	8	1	1,187	320	1,507	-	1,507
2035	-	-	-	-	126	140	711	214	115	10	1	1,317	321	1,638	-	1,638
2036	-	-	-	-	115	128	687	200	114	10	1	1,254	367	1,621	-	1,621
2037	-	-	-	-	104	116	698	188	119	9	1	1,236	405	1,641	-	1,641
2038	-	-	-	-	107	108	691	189	119	9	1	1,224	439	1,663	-	1,663
2039	-	-	-	-	105	100	672	186	123	10	1	1,196	470	1,667	-	1,667
2040	-	-	-	-	98	92	663	179	117	9	1	1,159	494	1,653	-	1,653
2041	-	-	-	-	91	84	652	170	117	9	0	1,124	516	1,639	-	1,639
2042	-	-	-	-	103	86	625	178	111	10	0	1,114	520	1,634	-	1,634
2043	-	-	-	-	107	153	599	179	109	11	0	1,158	527	1,686	-	1,686
2044	-	-	-	-	103	140	592	175	105	11	0	1,125	540	1,666	-	1,666
2045	-	-	-	-	99	129	589	172	105	11	0	1,105	546	1,651	-	1,651
2046	-	-	-	-	92	117	580	164	101	10	0	1,065	553	1,618	-	1,618
2047	-	-	-	-	83	107	551	153	99	10	0	1,004	549	1,553	-	1,553
2048	-	-	-	-	76	97	539	144	96	9	0	961	548	1,509	-	1,509
2049	-	-	-	-	68	88	512	135	94	9	0	905	540	1,445	-	1,445
2050	-	-	-	-	61	80	491	126	91	8	0	856	539	1,395	-	1,395
2051	-	-	-	-	54	72	476	118	89	7	0	817	535	1,352	-	1,352
2052	-	-	-	-	47	65	461	111	85	6	0	776	530	1,306	-	1,306
2053	-	-	-	-	43	59	440	104	83	6	0	736	517	1,252	-	1,252
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Mid Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	805	361	85	6	6	1,353	-	1,353	1	1,354
2022	24	2	1	27	105	11	769	335	86	7	6	1,346	-	1,346	1	1,346
2023	62	6	3	72	94	10	722	314	85	7	5	1,308	-	1,308	1	1,308
2024	92	10	5	107	84	9	667	295	86	7	4	1,259	-	1,259	1	1,259
2025	81	9	5	95	73	8	668	276	90	7	4	1,221	71	1,291	0	1,292
2026	72	8	4	85	59	7	680	259	99	6	4	1,200	119	1,319	0	1,319
2027	60	7	4	71	59	8	717	242	105	6	4	1,214	163	1,376	0	1,377
2028	54	7	4	65	57	8	776	228	112	6	4	1,256	204	1,460	0	1,460
2029	49	6	4	59	57	8	787	213	113	6	4	1,247	237	1,485	0	1,485
2030	44	5	4	54	56	8	788	200	118	6	4	1,232	270	1,502	0	1,502
2031	40	5	4	49	55	8	770	187	121	6	4	1,200	286	1,486	0	1,486
2032	37	5	4	45	53	7	771	176	119	6	3	1,180	306	1,486	0	1,486
2033	34	4	4	41	52	7	729	164	120	6	3	1,122	318	1,440	0	1,440
2034	30	4	3	38	94	25	701	186	114	8	1	1,168	307	1,475	0	1,475
2035	28	3	3	34	115	138	682	197	112	9	1	1,288	308	1,595	0	1,596
2036	25	3	3	32	108	126	659	190	112	9	1	1,237	352	1,588	0	1,589
2037	23	3	3	29	101	116	669	181	119	9	1	1,223	389	1,611	0	1,612
2038	23	3	3	28	100	107	663	178	117	9	1	1,203	421	1,624	0	1,624
2039	20	2	3	26	96	98	644	173	121	9	1	1,168	451	1,619	0	1,619
2040	18	2	3	23	90	90	636	166	116	9	0	1,131	474	1,605	0	1,605
2041	17	2	3	21	84	82	626	159	115	8	0	1,096	495	1,591	0	1,591
2042	15	2	2	19	97	85	601	167	110	10	0	1,088	500	1,588	0	1,588
2043	13	2	2	17	101	152	575	169	107	10	0	1,133	507	1,639	0	1,639
2044	12	1	2	16	97	139	570	166	104	10	0	1,102	520	1,622	0	1,622
2045	11	1	2	14	94	128	567	163	103	10	0	1,080	526	1,607	0	1,607
2046	10	1	2	13	90	117	560	158	100	10	0	1,048	533	1,581	0	1,581
2047	9	1	2	12	83	107	532	151	98	10	0	993	530	1,523	0	1,523
2048	8	1	2	11	76	97	519	141	95	9	0	948	528	1,476	0	1,476
2049	7	1	2	10	68	88	494	132	93	9	0	894	522	1,415	0	1,415
2050	6	1	2	9	61	80	474	124	89	7	0	844	521	1,365	0	1,365
2051	6	1	2	9	54	72	459	116	90	6	0	806	516	1,322	0	1,323
2052	5	1	1	7	47	65	448	109	84	6	0	766	515	1,281	0	1,281
2053	3	0	1	4	43	59	434	102	83	5	0	730	509	1,239	0	1,239
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Mid Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	PV $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(7)	-	(1)	(0)	(0)	19	-	19	1	19	2022
2023	62	6	3	72	-	-	(20)	-	(3)	0	(0)	49	-	49	1	49	2023
2024	92	10	5	107	-	-	(37)	-	(4)	0	(0)	65	-	65	1	66	2024
2025	81	9	5	95	-	-	(35)	-	(3)	0	(0)	56	(3)	53	0	53	2025
2026	72	8	4	85	-	-	(35)	-	(3)	0	(0)	47	(5)	41	0	41	2026
2027	60	7	4	71	(6)	(1)	(36)	-	(3)	(0)	(0)	25	(7)	18	0	18	2027
2028	54	7	4	65	(15)	(2)	(34)	-	(4)	(0)	(0)	9	(8)	1	0	1	2028
2029	49	6	4	59	(12)	(2)	(37)	-	(3)	(0)	(0)	4	(11)	(7)	0	(6)	2029
2030	44	5	4	54	(12)	(2)	(33)	-	(3)	(0)	0	4	(10)	(6)	0	(6)	2030
2031	40	5	4	49	(10)	(2)	(36)	-	(3)	(0)	0	(2)	(11)	(13)	0	(12)	2031
2032	37	5	4	45	(10)	(2)	(33)	-	(3)	(0)	0	(3)	(11)	(14)	0	(14)	2032
2033	34	4	4	41	(8)	(1)	(32)	-	(2)	(0)	0	(2)	(12)	(15)	0	(14)	2033
2034	30	4	3	38	(9)	(2)	(32)	(10)	(3)	(1)	(0)	(19)	(13)	(33)	0	(32)	2034
2035	28	3	3	34	(12)	(2)	(29)	(17)	(3)	(1)	(0)	(29)	(13)	(43)	0	(42)	2035
2036	25	3	3	32	(7)	(1)	(28)	(11)	(2)	(1)	(0)	(18)	(15)	(32)	0	(32)	2036
2037	23	3	3	29	(3)	(1)	(29)	(7)	(1)	(0)	(0)	(13)	(17)	(29)	0	(29)	2037
2038	23	3	3	28	(7)	(1)	(28)	(11)	(2)	(1)	(0)	(22)	(18)	(39)	0	(39)	2038
2039	20	2	3	26	(9)	(2)	(28)	(13)	(2)	(1)	(0)	(28)	(20)	(48)	0	(48)	2039
2040	18	2	3	23	(8)	(2)	(27)	(12)	(2)	(1)	(0)	(28)	(20)	(48)	0	(48)	2040
2041	17	2	3	21	(7)	(1)	(26)	(12)	(2)	(1)	(0)	(28)	(21)	(48)	0	(48)	2041
2042	15	2	2	19	(6)	(1)	(24)	(11)	(2)	(1)	(0)	(26)	(20)	(46)	0	(46)	2042
2043	13	2	2	17	(6)	(1)	(24)	(10)	(2)	(1)	(0)	(26)	(21)	(47)	0	(46)	2043
2044	12	1	2	16	(5)	(1)	(22)	(10)	(1)	(1)	(0)	(24)	(20)	(44)	0	(44)	2044
2045	11	1	2	14	(5)	(1)	(22)	(9)	(2)	(1)	(0)	(25)	(20)	(45)	0	(44)	2045
2046	10	1	2	13	(2)	(0)	(21)	(5)	(2)	(0)	(0)	(17)	(20)	(37)	0	(37)	2046
2047	9	1	2	12	(0)	(0)	(19)	(3)	(1)	(0)	(0)	(11)	(19)	(30)	0	(30)	2047
2048	8	1	2	11	(0)	(0)	(20)	(3)	(1)	(0)	(0)	(13)	(20)	(33)	0	(33)	2048
2049	7	1	2	10	(0)	(0)	(18)	(2)	(1)	(0)	(0)	(12)	(18)	(30)	0	(30)	2049
2050	6	1	2	9	(0)	(0)	(17)	(2)	(1)	(0)	(0)	(12)	(18)	(30)	0	(30)	2050
2051	6	1	2	9	(0)	(0)	(17)	(2)	1	(0)	(0)	(10)	(19)	(30)	0	(29)	2051
2052	5	1	1	7	(0)	(0)	(14)	(2)	(1)	(0)	(0)	(10)	(15)	(25)	0	(25)	2052
2053	3	0	1	4	(0)	(0)	(7)	(2)	(1)	(0)	(0)	(6)	(8)	(13)	0	(13)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in PV and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed beHIgh. As a part of this response please complete the table beHIgh and provide in electronic (Excel) format for each scenario.

a. HIgh Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

HIgh Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	812	361	86	6	6	1,360	-	1,360	-	1,360
2022	-	-	-	-	105	11	833	335	86	7	7	1,384	-	1,384	-	1,384
2023	-	-	-	-	94	10	871	314	87	7	8	1,390	-	1,390	-	1,390
2024	-	-	-	-	84	9	912	295	87	7	10	1,403	-	1,403	-	1,403
2025	-	-	-	-	73	8	919	276	93	7	8	1,383	81	1,464	-	1,464
2026	-	-	-	-	59	7	948	259	100	6	7	1,386	135	1,522	-	1,522
2027	-	-	-	-	65	9	984	242	107	6	6	1,419	179	1,598	-	1,598
2028	-	-	-	-	72	10	1,033	228	115	7	6	1,471	222	1,693	-	1,693
2029	-	-	-	-	69	10	1,043	213	116	6	6	1,462	257	1,719	-	1,719
2030	-	-	-	-	68	10	1,039	200	120	6	5	1,448	289	1,737	-	1,737
2031	-	-	-	-	65	9	1,034	187	123	6	5	1,429	308	1,737	-	1,737
2032	-	-	-	-	63	9	1,027	176	122	6	4	1,407	326	1,733	-	1,733
2033	-	-	-	-	60	9	970	164	122	6	4	1,335	343	1,678	-	1,678
2034	-	-	-	-	104	26	978	197	116	8	2	1,432	327	1,759	-	1,759
2035	-	-	-	-	126	140	965	214	116	10	1	1,572	321	1,893	-	1,893
2036	-	-	-	-	115	128	931	200	115	10	1	1,499	367	1,866	-	1,866
2037	-	-	-	-	104	116	955	188	120	9	1	1,494	405	1,899	-	1,899
2038	-	-	-	-	107	108	956	189	120	9	1	1,490	438	1,929	-	1,929
2039	-	-	-	-	105	100	925	186	124	10	1	1,450	470	1,920	-	1,920
2040	-	-	-	-	98	92	928	179	119	9	1	1,425	494	1,919	-	1,919
2041	-	-	-	-	91	84	921	170	118	9	0	1,394	515	1,909	-	1,909
2042	-	-	-	-	103	86	889	178	112	10	0	1,379	520	1,899	-	1,899
2043	-	-	-	-	107	153	862	179	110	11	0	1,422	527	1,950	-	1,950
2044	-	-	-	-	103	140	834	175	106	11	0	1,369	540	1,909	-	1,909
2045	-	-	-	-	99	129	831	172	105	11	0	1,347	546	1,893	-	1,893
2046	-	-	-	-	92	117	829	164	102	10	0	1,314	553	1,867	-	1,867
2047	-	-	-	-	83	107	803	153	100	10	0	1,257	549	1,806	-	1,806
2048	-	-	-	-	76	97	789	144	97	9	0	1,212	548	1,760	-	1,760
2049	-	-	-	-	68	88	750	135	94	9	0	1,145	540	1,685	-	1,685
2050	-	-	-	-	61	80	729	126	91	8	0	1,095	539	1,634	-	1,634
2051	-	-	-	-	54	72	706	118	90	7	0	1,048	535	1,583	-	1,583
2052	-	-	-	-	47	65	684	111	86	6	0	1,000	530	1,530	-	1,530
2053	-	-	-	-	43	59	654	104	84	6	0	949	516	1,466	-	1,466
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	812	361	86	6	6	1,360	-	1,360	1	1,361
2022	24	2	1	27	105	11	825	335	85	7	6	1,402	-	1,402	1	1,403
2023	62	6	3	72	94	10	847	314	83	7	8	1,434	-	1,434	1	1,435
2024	92	10	5	107	84	9	865	295	83	7	9	1,459	-	1,459	1	1,460
2025	81	9	5	95	73	8	874	276	89	7	8	1,430	78	1,507	0	1,508
2026	72	8	4	85	59	7	902	259	97	6	7	1,422	129	1,552	0	1,552
2027	60	7	4	71	59	8	938	242	104	6	6	1,434	171	1,605	0	1,606
2028	54	7	4	65	57	8	991	228	111	6	5	1,471	212	1,683	0	1,684
2029	49	6	4	59	57	8	997	213	113	6	5	1,458	246	1,704	0	1,704
2030	44	5	4	54	56	8	998	200	118	6	5	1,443	277	1,720	0	1,720
2031	40	5	4	49	55	8	988	187	121	6	5	1,418	294	1,712	0	1,712
2032	37	5	4	45	53	7	984	176	119	6	4	1,395	313	1,708	0	1,708
2033	34	4	4	41	52	7	929	164	119	6	4	1,323	330	1,653	0	1,653
2034	30	4	3	38	94	25	935	186	114	8	2	1,402	313	1,715	0	1,715
2035	28	3	3	34	115	138	925	197	113	9	1	1,532	308	1,840	0	1,840
2036	25	3	3	32	108	126	893	190	113	9	1	1,471	352	1,823	0	1,823
2037	23	3	3	29	101	116	915	181	120	9	1	1,470	388	1,858	0	1,859
2038	23	3	3	28	100	107	917	178	118	9	1	1,458	421	1,878	0	1,878
2039	20	2	3	26	96	98	886	173	122	9	1	1,411	451	1,862	0	1,862
2040	18	2	3	23	90	90	890	166	117	9	0	1,386	474	1,860	0	1,860
2041	17	2	3	21	84	82	884	159	116	8	0	1,355	495	1,850	0	1,850
2042	15	2	2	19	97	85	854	167	111	10	0	1,342	500	1,842	0	1,842
2043	13	2	2	17	101	152	828	169	108	10	0	1,386	507	1,893	0	1,893
2044	12	1	2	16	97	139	803	166	105	10	0	1,336	520	1,856	0	1,856
2045	11	1	2	14	94	128	799	163	104	10	0	1,313	526	1,840	0	1,840
2046	10	1	2	13	90	117	799	158	100	10	0	1,288	533	1,821	0	1,821
2047	9	1	2	12	83	107	775	151	99	10	0	1,236	530	1,766	0	1,766
2048	8	1	2	11	76	97	759	141	96	9	0	1,189	528	1,717	0	1,717
2049	7	1	2	10	68	88	724	132	93	9	0	1,125	522	1,646	0	1,646
2050	6	1	2	9	61	80	704	124	90	7	0	1,075	521	1,596	0	1,596
2051	6	1	2	9	54	72	681	116	91	6	0	1,029	516	1,545	0	1,545
2052	5	1	1	7	47	65	664	109	85	6	0	984	515	1,498	0	1,498
2053	3	0	1	4	43	59	644	102	83	5	0	941	509	1,449	0	1,449
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	PV $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(8)	-	(1)	(0)	(0)	18	-	18	1	19	2022
2023	62	6	3	72	-	-	(24)	-	(3)	0	(0)	45	-	45	1	45	2023
2024	92	10	5	107	-	-	(47)	-	(4)	0	(0)	56	-	56	1	56	2024
2025	81	9	5	95	-	-	(45)	-	(3)	0	(0)	46	(4)	43	0	43	2025
2026	72	8	4	85	-	-	(45)	-	(3)	0	(0)	36	(6)	30	0	31	2026
2027	60	7	4	71	(6)	(1)	(46)	-	(3)	(0)	(0)	15	(8)	7	0	8	2027
2028	54	7	4	65	(15)	(2)	(43)	-	(4)	(0)	(0)	0	(10)	(9)	0	(9)	2028
2029	49	6	4	59	(12)	(2)	(46)	-	(3)	(0)	(0)	(4)	(12)	(16)	0	(16)	2029
2030	44	5	4	54	(12)	(2)	(41)	-	(3)	(0)	(0)	(5)	(12)	(17)	0	(16)	2030
2031	40	5	4	49	(10)	(2)	(46)	-	(3)	(0)	(0)	(11)	(14)	(25)	0	(25)	2031
2032	37	5	4	45	(10)	(2)	(42)	-	(3)	(0)	(0)	(12)	(13)	(25)	0	(25)	2032
2033	34	4	4	41	(8)	(1)	(40)	-	(3)	(0)	(0)	(11)	(14)	(25)	0	(25)	2033
2034	30	4	3	38	(9)	(2)	(43)	(10)	(3)	(1)	(0)	(30)	(14)	(44)	0	(43)	2034
2035	28	3	3	34	(12)	(2)	(40)	(17)	(3)	(1)	(0)	(40)	(13)	(53)	0	(53)	2035
2036	25	3	3	32	(7)	(1)	(38)	(11)	(2)	(1)	(0)	(28)	(15)	(43)	0	(43)	2036
2037	23	3	3	29	(3)	(1)	(40)	(7)	(1)	(0)	(0)	(24)	(17)	(40)	0	(40)	2037
2038	23	3	3	28	(7)	(1)	(39)	(11)	(2)	(1)	(0)	(33)	(18)	(51)	0	(50)	2038
2039	20	2	3	26	(9)	(2)	(38)	(13)	(2)	(1)	(0)	(39)	(19)	(58)	0	(58)	2039
2040	18	2	3	23	(8)	(2)	(38)	(12)	(2)	(1)	(0)	(39)	(20)	(60)	0	(59)	2040
2041	17	2	3	21	(7)	(1)	(37)	(12)	(2)	(1)	(0)	(39)	(21)	(60)	0	(60)	2041
2042	15	2	2	19	(6)	(1)	(35)	(11)	(2)	(1)	(0)	(37)	(20)	(57)	0	(56)	2042
2043	13	2	2	17	(6)	(1)	(34)	(10)	(2)	(1)	(0)	(37)	(21)	(57)	0	(57)	2043
2044	12	1	2	16	(5)	(1)	(31)	(10)	(1)	(1)	(0)	(33)	(20)	(53)	0	(53)	2044
2045	11	1	2	14	(5)	(1)	(31)	(9)	(2)	(1)	(0)	(34)	(20)	(54)	0	(54)	2045
2046	10	1	2	13	(2)	(0)	(30)	(5)	(2)	(0)	(0)	(26)	(20)	(46)	0	(46)	2046
2047	9	1	2	12	(0)	(0)	(28)	(3)	(1)	(0)	(0)	(20)	(19)	(39)	0	(39)	2047
2048	8	1	2	11	(0)	(0)	(29)	(3)	(1)	(0)	(0)	(23)	(20)	(43)	0	(43)	2048
2049	7	1	2	10	(0)	(0)	(26)	(2)	(1)	(0)	(0)	(20)	(18)	(38)	0	(38)	2049
2050	6	1	2	9	(0)	(0)	(25)	(2)	(1)	(0)	(0)	(20)	(18)	(38)	0	(38)	2050
2051	6	1	2	9	(0)	(0)	(26)	(2)	1	(0)	(0)	(19)	(19)	(38)	0	(38)	2051
2052	5	1	1	7	(0)	(0)	(20)	(2)	(1)	(0)	(0)	(17)	(15)	(32)	0	(32)	2052
2053	3	0	1	4	(0)	(0)	(10)	(2)	(1)	(0)	(0)	(9)	(8)	(17)	0	(16)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in PV and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed below. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Low Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	805	361	85	6	6	1,353	-	1,353	-	1,353
2022	-	-	-	-	105	11	776	335	87	7	6	1,327	-	1,327	-	1,327
2023	-	-	-	-	94	10	742	314	88	7	5	1,259	-	1,259	-	1,259
2024	-	-	-	-	84	9	696	295	90	7	4	1,185	-	1,185	-	1,185
2025	-	-	-	-	73	8	677	276	93	7	4	1,138	74	1,211	-	1,211
2026	-	-	-	-	59	7	675	259	103	6	4	1,113	124	1,237	-	1,237
2027	-	-	-	-	65	9	699	242	109	6	4	1,134	168	1,302	-	1,302
2028	-	-	-	-	72	10	727	228	116	7	4	1,163	210	1,373	-	1,373
2029	-	-	-	-	69	10	730	213	118	6	3	1,150	241	1,391	-	1,391
2030	-	-	-	-	68	10	723	200	122	6	3	1,132	272	1,403	-	1,403
2031	-	-	-	-	65	9	716	187	125	6	3	1,111	291	1,402	-	1,402
2032	-	-	-	-	63	9	696	176	123	6	3	1,076	311	1,387	-	1,387
2033	-	-	-	-	60	9	656	164	123	6	2	1,020	327	1,347	-	1,347
2034	-	-	-	-	104	26	618	197	117	8	1	1,071	320	1,391	-	1,391
2035	-	-	-	-	126	140	596	214	114	10	1	1,202	321	1,523	-	1,523
2036	-	-	-	-	115	128	567	200	114	10	1	1,134	367	1,500	-	1,500
2037	-	-	-	-	104	116	574	188	119	9	1	1,111	405	1,516	-	1,516
2038	-	-	-	-	107	108	567	189	118	9	1	1,100	439	1,538	-	1,538
2039	-	-	-	-	105	100	550	186	123	10	1	1,074	471	1,544	-	1,544
2040	-	-	-	-	98	92	536	179	117	9	1	1,031	494	1,525	-	1,525
2041	-	-	-	-	91	84	528	170	117	9	0	999	516	1,515	-	1,515
2042	-	-	-	-	103	86	502	178	111	10	0	991	520	1,510	-	1,510
2043	-	-	-	-	107	153	476	179	109	11	0	1,035	527	1,563	-	1,563
2044	-	-	-	-	103	140	468	175	105	11	0	1,002	540	1,542	-	1,542
2045	-	-	-	-	99	129	463	172	104	11	0	978	546	1,524	-	1,524
2046	-	-	-	-	92	117	454	164	101	10	0	938	553	1,491	-	1,491
2047	-	-	-	-	83	107	430	153	99	10	0	882	549	1,431	-	1,431
2048	-	-	-	-	76	97	413	144	96	9	0	835	549	1,384	-	1,384
2049	-	-	-	-	68	88	386	135	93	9	0	780	540	1,320	-	1,320
2050	-	-	-	-	61	80	370	126	90	8	0	735	539	1,274	-	1,274
2051	-	-	-	-	54	72	358	118	89	7	0	699	535	1,234	-	1,234
2052	-	-	-	-	47	65	347	111	85	6	0	662	530	1,192	-	1,192
2053	-	-	-	-	43	59	332	104	83	6	0	626	517	1,143	-	1,143
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	81	8	805	361	85	6	6	1,353	-	1,353	1	1,354
2022	24	2	1	27	105	11	769	335	86	7	6	1,346	-	1,346	1	1,346
2023	62	6	3	72	94	10	722	314	85	7	5	1,308	-	1,308	1	1,308
2024	92	10	5	107	84	9	659	295	86	7	4	1,250	-	1,250	1	1,251
2025	81	9	5	95	73	8	643	276	90	7	4	1,195	70	1,265	0	1,266
2026	72	8	4	85	59	7	642	259	100	6	4	1,161	118	1,279	0	1,280
2027	60	7	4	71	59	8	666	242	106	6	4	1,162	161	1,324	0	1,324
2028	54	7	4	65	57	8	696	228	113	6	4	1,176	202	1,378	0	1,378
2029	49	6	4	59	57	8	697	213	114	6	4	1,157	233	1,390	0	1,391
2030	44	5	4	54	56	8	695	200	118	6	3	1,139	263	1,402	0	1,402
2031	40	5	4	49	55	8	684	187	122	6	3	1,114	281	1,395	0	1,395
2032	37	5	4	45	53	7	668	176	119	6	3	1,078	300	1,378	0	1,378
2033	34	4	4	41	52	7	629	164	120	6	2	1,023	315	1,338	0	1,338
2034	30	4	3	38	94	25	591	186	114	8	1	1,057	306	1,362	0	1,362
2035	28	3	3	34	115	138	572	197	112	9	1	1,177	308	1,485	0	1,486
2036	25	3	3	32	108	126	544	190	112	9	1	1,121	352	1,473	0	1,473
2037	23	3	3	29	101	116	550	181	118	9	1	1,104	389	1,492	0	1,492
2038	23	3	3	28	100	107	544	178	116	9	1	1,083	421	1,504	0	1,504
2039	20	2	3	26	96	98	527	173	121	9	1	1,050	451	1,501	0	1,502
2040	18	2	3	23	90	90	514	166	115	9	0	1,008	474	1,482	0	1,482
2041	17	2	3	21	84	82	506	159	115	8	0	977	495	1,472	0	1,472
2042	15	2	2	19	97	85	482	167	109	10	0	970	500	1,469	0	1,469
2043	13	2	2	17	101	152	457	169	107	10	0	1,014	507	1,521	0	1,521
2044	12	1	2	16	97	139	451	166	104	10	0	982	520	1,503	0	1,503
2045	11	1	2	14	94	128	445	163	103	10	0	958	526	1,484	0	1,485
2046	10	1	2	13	90	117	438	158	99	10	0	925	533	1,458	0	1,459
2047	9	1	2	12	83	107	415	151	98	10	0	875	530	1,405	0	1,405
2048	8	1	2	11	76	97	398	141	95	9	0	827	528	1,355	0	1,355
2049	7	1	2	10	68	88	373	132	92	9	0	772	522	1,294	0	1,294
2050	6	1	2	9	61	80	357	124	89	7	0	727	521	1,248	0	1,248
2051	6	1	2	9	54	72	346	116	90	6	0	693	516	1,209	0	1,209
2052	5	1	1	7	47	65	337	109	84	6	0	655	515	1,170	0	1,170
2053	3	0	1	4	43	59	327	102	83	5	0	622	509	1,131	0	1,131
PV $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

PV $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	PV $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	24	2	1	27	-	-	(7)	-	(1)	(0)	(0)	19	-	19	1	19	2022
2023	62	6	3	72	-	-	(20)	-	(3)	0	(0)	48	-	48	1	49	2023
2024	92	10	5	107	-	-	(37)	-	(4)	0	(0)	66	-	66	1	66	2024
2025	81	9	5	95	-	-	(34)	-	(3)	0	(0)	57	(3)	54	0	55	2025
2026	72	8	4	85	-	-	(34)	-	(3)	0	(0)	48	(5)	42	0	43	2026
2027	60	7	4	71	(6)	(1)	(33)	-	(3)	(0)	(0)	28	(7)	21	0	22	2027
2028	54	7	4	65	(15)	(2)	(30)	-	(4)	(0)	0	13	(8)	5	0	6	2028
2029	49	6	4	59	(12)	(2)	(33)	-	(4)	(0)	0	8	(8)	(0)	0	(0)	2029
2030	44	5	4	54	(12)	(2)	(28)	-	(4)	(0)	0	7	(9)	(1)	0	(1)	2030
2031	40	5	4	49	(10)	(2)	(31)	-	(3)	(0)	0	3	(10)	(7)	0	(6)	2031
2032	37	5	4	45	(10)	(2)	(28)	-	(3)	(0)	0	2	(11)	(9)	0	(9)	2032
2033	34	4	4	41	(8)	(1)	(27)	-	(2)	(0)	0	3	(12)	(10)	0	(9)	2033
2034	30	4	3	38	(9)	(2)	(27)	(10)	(3)	(1)	(0)	(15)	(14)	(29)	0	(28)	2034
2035	28	3	3	34	(12)	(2)	(24)	(17)	(3)	(1)	(0)	(24)	(13)	(38)	0	(37)	2035
2036	25	3	3	32	(7)	(1)	(23)	(11)	(2)	(1)	(0)	(13)	(15)	(27)	0	(27)	2036
2037	23	3	3	29	(3)	(1)	(24)	(7)	(1)	(0)	(0)	(7)	(17)	(24)	0	(24)	2037
2038	23	3	3	28	(7)	(1)	(23)	(11)	(2)	(1)	(0)	(16)	(18)	(34)	0	(34)	2038
2039	20	2	3	26	(9)	(2)	(23)	(13)	(2)	(1)	(0)	(23)	(19)	(43)	0	(42)	2039
2040	18	2	3	23	(8)	(2)	(22)	(12)	(2)	(1)	(0)	(23)	(20)	(43)	0	(43)	2040
2041	17	2	3	21	(7)	(1)	(21)	(12)	(2)	(1)	(0)	(22)	(21)	(43)	0	(43)	2041
2042	15	2	2	19	(6)	(1)	(19)	(11)	(2)	(1)	(0)	(21)	(20)	(41)	0	(41)	2042
2043	13	2	2	17	(6)	(1)	(19)	(10)	(2)	(1)	(0)	(21)	(21)	(42)	0	(42)	2043
2044	12	1	2	16	(5)	(1)	(17)	(10)	(1)	(1)	(0)	(19)	(20)	(39)	0	(39)	2044
2045	11	1	2	14	(5)	(1)	(17)	(9)	(2)	(1)	(0)	(20)	(20)	(40)	0	(40)	2045
2046	10	1	2	13	(2)	(0)	(16)	(5)	(2)	(0)	(0)	(13)	(20)	(32)	0	(32)	2046
2047	9	1	2	12	(0)	(0)	(15)	(3)	(1)	(0)	(0)	(7)	(19)	(26)	0	(26)	2047
2048	8	1	2	11	(0)	(0)	(15)	(3)	(1)	(0)	(0)	(9)	(20)	(29)	0	(29)	2048
2049	7	1	2	10	(0)	(0)	(13)	(2)	(1)	(0)	(0)	(7)	(18)	(26)	0	(26)	2049
2050	6	1	2	9	(0)	(0)	(13)	(2)	(1)	(0)	(0)	(8)	(18)	(26)	0	(26)	2050
2051	6	1	2	9	(0)	(0)	(13)	(2)	1	(0)	(0)	(6)	(19)	(25)	0	(25)	2051
2052	5	1	1	7	(0)	(0)	(10)	(2)	(1)	(0)	(0)	(6)	(15)	(22)	0	(22)	2052
2053	3	0	1	4	(0)	(0)	(5)	(2)	(1)	(0)	(0)	(4)	(8)	(12)	0	(12)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

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a. Mid Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Mid Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020				-	57	4	850	391	86	4	6	1,398	-	1,398		1,398
2021				-	87	9	859	385	91	6	6	1,444	-	1,444		1,444
2022				-	120	12	884	382	99	8	6	1,511	-	1,511		1,511
2023				-	114	12	902	382	107	8	6	1,530	-	1,530		1,530
2024				-	109	11	913	383	117	9	6	1,547	-	1,547		1,547
2025				-	101	11	972	382	129	9	6	1,610	102	1,713		1,713
2026				-	86	11	1,056	382	151	9	6	1,701	184	1,886		1,886
2027				-	102	13	1,187	382	171	10	7	1,872	267	2,139		2,139
2028				-	121	17	1,360	383	195	11	7	2,094	358	2,451		2,451
2029				-	124	17	1,477	382	208	12	8	2,228	445	2,673		2,673
2030				-	130	18	1,569	382	232	12	8	2,351	534	2,885		2,885
2031				-	132	19	1,646	382	253	13	8	2,452	605	3,057		3,057
2032				-	138	20	1,750	383	266	13	7	2,577	690	3,267		3,267
2033				-	140	20	1,766	382	284	14	6	2,614	767	3,380		3,380
2034				-	257	66	1,818	488	290	21	3	2,943	794	3,737		3,737
2035				-	335	370	1,881	566	304	27	2	3,484	850	4,333		4,333
2036				-	324	360	1,939	566	322	27	2	3,540	1,035	4,575		4,575
2037				-	314	351	2,101	566	360	28	2	3,721	1,220	4,941		4,941
2038				-	343	348	2,221	608	382	31	2	3,934	1,409	5,343		5,343
2039				-	359	343	2,304	639	422	33	2	4,102	1,613	5,715		5,715
2040				-	359	335	2,426	654	430	34	2	4,241	1,807	6,048		6,048
2041				-	356	327	2,544	665	456	36	2	4,386	2,013	6,399		6,399
2042				-	429	359	2,602	742	464	42	2	4,640	2,165	6,805		6,805
2043				-	475	679	2,663	797	485	48	2	5,148	2,344	7,492		7,492
2044				-	486	664	2,805	830	499	50	2	5,337	2,561	7,898		7,898
2045				-	502	651	2,982	871	530	54	2	5,591	2,764	8,355		8,355
2046				-	495	633	3,133	883	546	56	2	5,749	2,985	8,734		8,734
2047				-	479	614	3,176	883	572	57	2	5,783	3,164	8,947		8,947
2048				-	465	595	3,310	883	592	58	2	5,906	3,371	9,277		9,277
2049				-	449	576	3,354	883	615	58	2	5,937	3,542	9,479		9,479
2050				-	427	557	3,435	883	634	53	2	5,991	3,774	9,765		9,765
2051				-	405	539	3,553	883	665	50	2	6,097	3,997	10,094		10,094
2052				-	378	520	3,674	883	679	47	2	6,183	4,224	10,407		10,407
2053				-	366	501	3,744	883	709	48	2	6,253	4,391	10,644		10,644
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Mid Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	87	9	859	385	91	6	6	1,444	-	1,444	1	1,445
2022	27	3	1	31	120	12	875	382	98	8	6	1,532	-	1,532	1	1,533
2023	76	8	4	87	114	12	878	382	103	8	6	1,589	-	1,589	1	1,589
2024	119	13	6	138	109	11	865	383	112	9	5	1,631	-	1,631	1	1,632
2025	113	12	6	131	101	11	924	382	125	9	6	1,688	98	1,786	1	1,786
2026	107	12	7	125	86	11	1,004	382	146	9	6	1,770	176	1,946	1	1,947
2027	94	11	7	112	93	12	1,130	382	166	10	6	1,911	256	2,167	1	2,168
2028	90	11	7	109	96	13	1,303	383	189	10	7	2,109	344	2,453	1	2,453
2029	87	11	8	105	103	14	1,410	382	203	11	8	2,236	426	2,661	1	2,662
2030	85	11	8	103	106	14	1,507	382	226	11	8	2,357	516	2,873	1	2,874
2031	82	10	8	101	113	16	1,572	382	246	12	8	2,449	583	3,032	0	3,032
2032	80	10	8	98	116	16	1,678	383	259	12	7	2,571	665	3,236	0	3,236
2033	78	10	8	96	122	17	1,693	382	279	13	6	2,608	739	3,347	0	3,347
2034	76	9	9	93	234	61	1,739	462	283	19	3	2,895	761	3,656	0	3,657
2035	73	9	9	91	303	364	1,803	522	297	24	2	3,406	814	4,220	0	4,221
2036	71	9	9	89	305	357	1,860	535	317	25	2	3,490	993	4,483	0	4,484
2037	69	8	9	87	304	349	2,013	545	357	27	2	3,683	1,170	4,853	0	4,853
2038	73	8	9	91	321	343	2,131	573	375	29	2	3,865	1,352	5,217	0	5,218
2039	70	8	10	88	329	337	2,209	594	415	30	2	4,004	1,546	5,551	0	5,551
2040	67	8	10	85	331	330	2,327	609	423	32	2	4,138	1,733	5,871	0	5,871
2041	65	7	10	82	329	322	2,442	619	450	33	2	4,279	1,932	6,211	0	6,211
2042	62	7	10	80	403	354	2,502	697	457	40	2	4,533	2,081	6,614	0	6,615
2043	59	7	11	77	449	674	2,557	752	478	45	2	5,033	2,252	7,285	0	7,286
2044	57	7	11	75	461	659	2,700	785	493	47	2	5,223	2,467	7,690	0	7,691
2045	55	7	11	73	478	646	2,871	825	522	51	2	5,467	2,663	8,130	1	8,130
2046	53	7	11	71	485	631	3,021	855	538	53	2	5,656	2,878	8,534	0	8,535
2047	50	6	12	68	478	614	3,065	867	567	55	2	5,718	3,054	8,772	0	8,772
2048	48	6	12	66	465	595	3,188	867	584	57	2	5,824	3,248	9,072	0	9,072
2049	46	6	12	64	448	576	3,239	867	607	56	2	5,860	3,421	9,281	0	9,282
2050	44	6	13	62	426	557	3,316	867	626	51	2	5,909	3,645	9,554	0	9,555
2051	45	6	13	64	405	538	3,425	867	671	48	2	6,020	3,854	9,874	1	9,874
2052	39	5	11	54	378	519	3,565	867	673	45	2	6,105	4,101	10,206	0	10,206
2053	24	2	5	31	366	501	3,688	867	704	46	2	6,206	4,325	10,531	0	10,531
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Mid Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	Nominal $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	27	3	1	31	-	-	(8)	-	(1)	(0)	(0)	21	-	21	1	22	2022
2023	76	8	4	87	-	-	(24)	-	(4)	0	(0)	59	-	59	1	60	2023
2024	119	13	6	138	-	-	(48)	-	(5)	0	(0)	84	-	84	1	85	2024
2025	113	12	6	131	-	-	(49)	-	(4)	0	(0)	78	(5)	73	1	74	2025
2026	107	12	7	125	-	-	(52)	-	(5)	0	(0)	69	(8)	61	1	61	2026
2027	94	11	7	112	(9)	(2)	(57)	-	(5)	(0)	(0)	39	(11)	28	1	29	2027
2028	90	11	7	109	(25)	(4)	(57)	-	(6)	(1)	(0)	16	(14)	2	1	2	2028
2029	87	11	8	105	(21)	(3)	(67)	-	(5)	(1)	(0)	7	(20)	(12)	1	(12)	2029
2030	85	11	8	103	(23)	(4)	(62)	-	(6)	(1)	0	7	(18)	(12)	1	(11)	2030
2031	82	10	8	101	(20)	(3)	(73)	-	(7)	(1)	0	(3)	(22)	(26)	0	(25)	2031
2032	80	10	8	98	(22)	(4)	(72)	-	(6)	(1)	0	(6)	(25)	(31)	0	(31)	2032
2033	78	10	8	96	(18)	(3)	(74)	-	(6)	(1)	0	(6)	(28)	(34)	0	(33)	2033
2034	76	9	9	93	(23)	(4)	(79)	(26)	(7)	(2)	(0)	(48)	(33)	(81)	0	(80)	2034
2035	73	9	9	91	(32)	(6)	(78)	(44)	(7)	(2)	(0)	(78)	(35)	(113)	0	(112)	2035
2036	71	9	9	89	(19)	(4)	(79)	(31)	(5)	(2)	(0)	(50)	(42)	(92)	0	(91)	2036
2037	69	8	9	87	(10)	(2)	(88)	(21)	(2)	(1)	(0)	(38)	(50)	(88)	0	(88)	2037
2038	73	8	9	91	(22)	(4)	(90)	(35)	(7)	(2)	(0)	(69)	(57)	(126)	0	(126)	2038
2039	70	8	10	88	(29)	(6)	(95)	(45)	(7)	(3)	(0)	(97)	(67)	(164)	0	(164)	2039
2040	67	8	10	85	(28)	(5)	(99)	(45)	(7)	(3)	(0)	(103)	(74)	(177)	0	(176)	2040
2041	65	7	10	82	(27)	(5)	(102)	(45)	(7)	(3)	(0)	(107)	(81)	(188)	0	(188)	2041
2042	62	7	10	80	(27)	(5)	(100)	(45)	(7)	(3)	(0)	(108)	(84)	(191)	0	(191)	2042
2043	59	7	11	77	(26)	(5)	(106)	(45)	(8)	(3)	(0)	(115)	(92)	(207)	0	(206)	2043
2044	57	7	11	75	(25)	(5)	(104)	(45)	(6)	(3)	(0)	(113)	(94)	(208)	0	(207)	2044
2045	55	7	11	73	(24)	(5)	(111)	(45)	(8)	(3)	(0)	(124)	(101)	(226)	1	(225)	2045
2046	53	7	11	71	(10)	(2)	(113)	(28)	(8)	(2)	(0)	(93)	(106)	(199)	0	(199)	2046
2047	50	6	12	68	(1)	(0)	(111)	(16)	(4)	(2)	(0)	(65)	(109)	(175)	0	(174)	2047
2048	48	6	12	66	(1)	(0)	(122)	(16)	(8)	(2)	(0)	(82)	(123)	(206)	0	(205)	2048
2049	46	6	12	64	(1)	(0)	(115)	(16)	(7)	(2)	(0)	(77)	(121)	(198)	0	(197)	2049
2050	44	6	13	62	(1)	(0)	(119)	(16)	(7)	(2)	(0)	(82)	(128)	(211)	0	(210)	2050
2051	45	6	13	64	(1)	(0)	(128)	(16)	6	(2)	(0)	(77)	(144)	(220)	1	(220)	2051
2052	39	5	11	54	(0)	(0)	(108)	(16)	(6)	(2)	(0)	(78)	(123)	(202)	0	(201)	2052
2053	24	2	5	31	(0)	(0)	(56)	(16)	(5)	(2)	(0)	(48)	(65)	(113)	0	(113)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in nominal and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed beHIgh. As a part of this response please complete the table beHIgh and provide in electronic (Excel) format for each scenario.

a. HIgh Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

HIgh Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020				-	57	4	850	391	86	4	6	1,398	-	1,398		1,398
2021				-	87	9	866	385	91	6	7	1,451	-	1,451		1,451
2022				-	120	12	948	382	98	8	7	1,576	-	1,576		1,576
2023				-	114	12	1,058	382	105	8	9	1,688	-	1,688		1,688
2024				-	109	11	1,182	383	112	9	13	1,819	-	1,819		1,819
2025				-	101	11	1,271	382	128	9	11	1,913	112	2,025		2,025
2026				-	86	11	1,399	382	148	9	10	2,046	200	2,245		2,245
2027				-	102	13	1,549	382	169	10	9	2,234	282	2,516		2,516
2028				-	121	17	1,736	383	194	11	10	2,471	373	2,844		2,844
2029				-	124	17	1,869	382	207	12	10	2,621	461	3,082		3,082
2030				-	130	18	1,987	382	230	12	10	2,769	553	3,322		3,322
2031				-	132	19	2,110	382	251	13	10	2,917	628	3,545		3,545
2032				-	138	20	2,235	383	265	13	9	3,063	711	3,774		3,774
2033				-	140	20	2,253	382	282	14	9	3,101	798	3,899		3,899
2034				-	257	66	2,425	488	289	21	4	3,549	811	4,360		4,360
2035				-	335	370	2,553	566	307	27	2	4,158	849	5,007		5,007
2036				-	324	360	2,628	566	324	27	2	4,231	1,034	5,266		5,266
2037				-	314	351	2,876	566	362	28	2	4,498	1,220	5,719		5,719
2038				-	343	348	3,073	608	385	31	2	4,789	1,409	6,198		6,198
2039				-	359	343	3,171	639	426	33	2	4,971	1,612	6,583		6,583
2040				-	359	335	3,395	654	434	34	2	5,214	1,806	7,021		7,021
2041				-	356	327	3,595	665	461	36	2	5,442	2,012	7,453		7,453
2042				-	429	359	3,701	742	468	42	2	5,743	2,165	7,908		7,908
2043				-	475	679	3,832	797	489	48	2	6,322	2,344	8,665		8,665
2044				-	486	664	3,955	830	503	50	2	6,490	2,561	9,051		9,051
2045				-	502	651	4,203	871	533	54	2	6,816	2,764	9,580		9,580
2046				-	495	633	4,476	883	551	56	2	7,095	2,985	10,080		10,080
2047				-	479	614	4,626	883	576	57	2	7,238	3,164	10,401		10,401
2048				-	465	595	4,846	883	597	58	2	7,447	3,371	10,818		10,818
2049				-	449	576	4,919	883	620	58	2	7,507	3,542	11,048		11,048
2050				-	427	557	5,100	883	639	53	2	7,661	3,773	11,434		11,434
2051				-	405	539	5,275	883	670	50	2	7,824	3,997	11,821		11,821
2052				-	378	520	5,453	883	685	47	2	7,968	4,224	12,192		12,192
2053				-	366	501	5,556	883	715	48	2	8,071	4,390	12,461		12,461
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	87	9	866	385	91	6	7	1,451	-	1,451	1	1,452
2022	27	3	1	31	120	12	939	382	97	8	7	1,596	-	1,596	1	1,597
2023	76	8	4	87	114	12	1,029	382	101	8	9	1,742	-	1,742	1	1,743
2024	119	13	6	138	109	11	1,121	383	108	9	12	1,891	-	1,891	1	1,892
2025	113	12	6	131	101	11	1,209	382	124	9	10	1,977	107	2,085	1	2,085
2026	107	12	7	125	86	11	1,332	382	144	9	10	2,099	191	2,290	1	2,291
2027	94	11	7	112	93	12	1,477	382	164	10	9	2,258	270	2,528	1	2,528
2028	90	11	7	109	96	13	1,665	383	187	10	9	2,472	356	2,828	1	2,829
2029	87	11	8	105	103	14	1,787	382	202	11	9	2,613	441	3,054	1	3,054
2030	85	11	8	103	106	14	1,909	382	225	11	10	2,760	530	3,290	1	3,290
2031	82	10	8	101	113	16	2,016	382	246	12	9	2,894	600	3,493	0	3,494
2032	80	10	8	98	116	16	2,143	383	259	12	9	3,037	683	3,719	0	3,720
2033	78	10	8	96	122	17	2,159	382	276	13	9	3,075	766	3,841	0	3,841
2034	76	9	9	93	234	61	2,319	462	282	19	4	3,475	777	4,252	0	4,252
2035	73	9	9	91	303	364	2,447	522	299	24	2	4,052	814	4,866	0	4,867
2036	71	9	9	89	305	357	2,520	535	320	25	2	4,153	993	5,145	0	5,146
2037	69	8	9	87	304	349	2,755	545	360	27	2	4,427	1,170	5,597	0	5,597
2038	73	8	9	91	321	343	2,947	573	378	29	2	4,684	1,352	6,035	0	6,036
2039	70	8	10	88	329	337	3,039	594	418	30	2	4,837	1,546	6,383	0	6,384
2040	67	8	10	85	331	330	3,255	609	427	32	2	5,070	1,733	6,803	0	6,803
2041	65	7	10	82	329	322	3,449	619	454	33	2	5,289	1,931	7,220	0	7,221
2042	62	7	10	80	403	354	3,556	697	461	40	2	5,591	2,081	7,672	0	7,672
2043	59	7	11	77	449	674	3,679	752	481	45	2	6,159	2,252	8,411	0	8,411
2044	57	7	11	75	461	659	3,807	785	497	47	2	6,334	2,467	8,801	0	8,801
2045	55	7	11	73	478	646	4,045	825	526	51	2	6,645	2,663	9,308	1	9,308
2046	53	7	11	71	485	631	4,314	855	542	53	2	6,953	2,878	9,831	0	9,832
2047	50	6	12	68	478	614	4,463	867	572	55	2	7,121	3,054	10,175	0	10,175
2048	48	6	12	66	465	595	4,666	867	589	57	2	7,307	3,247	10,555	0	10,555
2049	46	6	12	64	448	576	4,749	867	613	56	2	7,375	3,421	10,796	0	10,797
2050	44	6	13	62	426	557	4,923	867	631	51	2	7,521	3,645	11,166	0	11,166
2051	45	6	13	64	405	538	5,083	867	676	48	2	7,683	3,853	11,536	1	11,537
2052	39	5	11	54	378	519	5,291	867	679	45	2	7,836	4,101	11,937	0	11,937
2053	24	2	5	31	366	501	5,472	867	710	46	2	7,995	4,325	12,320	0	12,321
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

HIgh Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	Nominal $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	27	3	1	31	-	-	(9)	-	(1)	(0)	(0)	21	-	21	1	21	2022
2023	76	8	4	87	-	-	(29)	-	(4)	0	(0)	54	-	54	1	55	2023
2024	119	13	6	138	-	-	(61)	-	(5)	0	(1)	72	-	72	1	73	2024
2025	113	12	6	131	-	-	(62)	-	(4)	0	(0)	64	(5)	59	1	60	2025
2026	107	12	7	125	-	-	(67)	-	(5)	0	(0)	53	(9)	45	1	45	2026
2027	94	11	7	112	(9)	(2)	(72)	-	(5)	(0)	(0)	24	(12)	12	1	12	2027
2028	90	11	7	109	(25)	(4)	(71)	-	(6)	(1)	(0)	1	(16)	(16)	1	(15)	2028
2029	87	11	8	105	(21)	(3)	(82)	-	(6)	(1)	(1)	(8)	(21)	(28)	1	(28)	2029
2030	85	11	8	103	(23)	(4)	(78)	-	(6)	(1)	(0)	(9)	(23)	(32)	1	(32)	2030
2031	82	10	8	101	(20)	(3)	(94)	-	(5)	(1)	(1)	(23)	(29)	(51)	0	(51)	2031
2032	80	10	8	98	(22)	(4)	(92)	-	(6)	(1)	(0)	(27)	(28)	(55)	0	(54)	2032
2033	78	10	8	96	(18)	(3)	(93)	-	(6)	(1)	(0)	(26)	(31)	(58)	0	(57)	2033
2034	76	9	9	93	(23)	(4)	(106)	(26)	(7)	(2)	(0)	(74)	(34)	(108)	0	(108)	2034
2035	73	9	9	91	(32)	(6)	(106)	(44)	(7)	(2)	(0)	(106)	(35)	(141)	0	(141)	2035
2036	71	9	9	89	(19)	(4)	(108)	(31)	(5)	(2)	(0)	(79)	(42)	(121)	0	(120)	2036
2037	69	8	9	87	(10)	(2)	(121)	(21)	(3)	(1)	(0)	(71)	(50)	(122)	0	(121)	2037
2038	73	8	9	91	(22)	(4)	(126)	(35)	(7)	(2)	(0)	(105)	(57)	(163)	0	(162)	2038
2039	70	8	10	88	(29)	(6)	(131)	(45)	(7)	(3)	(0)	(134)	(67)	(200)	0	(200)	2039
2040	67	8	10	85	(28)	(5)	(140)	(45)	(7)	(3)	(0)	(144)	(74)	(218)	0	(217)	2040
2041	65	7	10	82	(27)	(5)	(146)	(45)	(7)	(3)	(0)	(152)	(81)	(233)	0	(233)	2041
2042	62	7	10	80	(27)	(5)	(145)	(45)	(7)	(3)	(0)	(152)	(84)	(236)	0	(235)	2042
2043	59	7	11	77	(26)	(5)	(153)	(45)	(8)	(3)	(0)	(163)	(92)	(254)	0	(254)	2043
2044	57	7	11	75	(25)	(5)	(148)	(45)	(5)	(3)	(0)	(156)	(94)	(251)	0	(250)	2044
2045	55	7	11	73	(24)	(5)	(158)	(45)	(8)	(3)	(0)	(170)	(102)	(272)	1	(271)	2045
2046	53	7	11	71	(10)	(2)	(162)	(28)	(8)	(2)	(0)	(142)	(106)	(249)	0	(248)	2046
2047	50	6	12	68	(1)	(0)	(163)	(16)	(4)	(2)	(0)	(117)	(110)	(227)	0	(226)	2047
2048	48	6	12	66	(1)	(0)	(180)	(16)	(8)	(2)	(0)	(140)	(123)	(263)	0	(263)	2048
2049	46	6	12	64	(1)	(0)	(170)	(16)	(7)	(2)	(0)	(131)	(120)	(252)	0	(251)	2049
2050	44	6	13	62	(1)	(0)	(177)	(16)	(7)	(2)	(0)	(141)	(128)	(269)	0	(268)	2050
2051	45	6	13	64	(1)	(0)	(192)	(16)	6	(2)	(0)	(141)	(144)	(284)	1	(284)	2051
2052	39	5	11	54	(0)	(0)	(162)	(16)	(6)	(2)	(0)	(132)	(123)	(255)	0	(255)	2052
2053	24	2	5	31	(0)	(0)	(84)	(16)	(5)	(2)	(0)	(76)	(65)	(141)	0	(140)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

11 Please refer to DEF witness Borsch's direct testimony, Exhibit BMHB-3 and BMHB-5. Provide the annual and cumulative revenue requirements (in nominal and net present value) over the life of the proposed CEC projects for each resource plan ("Base Case" without the CEC and the "CEC Case" with the CEC) and the difference between the two plans for each of the scenarios listed below. As a part of this response please complete the table below and provide in electronic (Excel) format for each scenario.

a. Low Fuel Scenario
b. Mid Fuel Scenario
c. High Fuel Scenario

Low Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	INCR. O&M	Non Carbon Emissions					
2020				-	57	4	850	391	86	4	6	1,398	-	1,398		1,398
2021				-	87	9	859	385	91	6	6	1,444	-	1,444		1,444
2022				-	120	12	884	382	99	8	6	1,511	-	1,511		1,511
2023				-	114	12	902	382	107	8	6	1,530	-	1,530		1,530
2024				-	109	11	902	383	116	9	6	1,536	-	1,536		1,536
2025				-	101	11	936	382	129	9	6	1,573	102	1,675		1,675
2026				-	86	11	997	382	152	9	6	1,642	183	1,825		1,825
2027				-	102	13	1,101	382	171	10	6	1,786	264	2,051		2,051
2028				-	121	17	1,221	383	195	11	6	1,954	352	2,306		2,306
2029				-	124	17	1,309	382	211	12	6	2,061	432	2,493		2,493
2030				-	130	18	1,383	382	234	12	6	2,165	519	2,684		2,684
2031				-	132	19	1,460	382	255	13	6	2,267	594	2,861		2,861
2032				-	138	20	1,516	383	268	13	6	2,343	676	3,020		3,020
2033				-	140	20	1,523	382	285	14	6	2,370	760	3,130		3,130
2034				-	257	66	1,532	488	289	21	3	2,656	792	3,448		3,448
2035				-	335	370	1,578	566	303	27	2	3,179	850	4,029		4,029
2036				-	324	360	1,601	566	321	27	2	3,200	1,035	4,235		4,235
2037				-	314	351	1,727	566	358	28	2	3,345	1,221	4,566		4,566
2038				-	343	348	1,822	608	380	31	2	3,533	1,410	4,943		4,943
2039				-	359	343	1,885	639	421	33	2	3,681	1,613	5,294		5,294
2040				-	359	335	1,959	654	428	34	2	3,772	1,807	5,579		5,579
2041				-	356	327	2,059	665	455	36	2	3,900	2,013	5,913		5,913
2042				-	429	359	2,089	742	462	42	2	4,126	2,165	6,291		6,291
2043				-	475	679	2,116	797	484	48	2	4,600	2,344	6,944		6,944
2044				-	486	664	2,220	830	497	50	2	4,750	2,561	7,311		7,311
2045				-	502	651	2,341	871	527	54	2	4,948	2,765	7,713		7,713
2046				-	495	633	2,450	883	544	56	2	5,063	2,985	8,048		8,048
2047				-	479	614	2,477	883	569	57	2	5,081	3,164	8,245		8,245
2048				-	465	595	2,541	883	590	58	2	5,135	3,371	8,506		8,506
2049				-	449	576	2,533	883	612	58	2	5,113	3,542	8,655		8,655
2050				-	427	557	2,587	883	631	53	2	5,141	3,774	8,915		8,915
2051				-	405	539	2,676	883	663	50	2	5,217	3,997	9,215		9,215
2052				-	378	520	2,766	883	677	47	2	5,272	4,225	9,497		9,497
2053				-	366	501	2,818	883	707	48	2	5,325	4,391	9,715		9,715
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	INCR. O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	INCR. O&M	Non Carbon Emissions					
2020	-	-	-	-	57	4	850	391	86	4	6	1,398	-	1,398	-	1,398
2021	-	-	-	-	87	9	859	385	91	6	6	1,444	-	1,444	1	1,445
2022	27	3	1	31	120	12	875	382	98	8	6	1,532	-	1,532	1	1,533
2023	76	8	4	87	114	12	877	382	103	8	6	1,589	-	1,589	1	1,589
2024	119	13	6	138	109	11	854	383	111	9	5	1,621	-	1,621	1	1,621
2025	113	12	6	131	101	11	889	382	124	9	6	1,653	97	1,750	1	1,750
2026	107	12	7	125	86	11	947	382	147	9	6	1,713	175	1,888	1	1,888
2027	94	11	7	112	93	12	1,049	382	166	10	6	1,830	254	2,084	1	2,085
2028	90	11	7	109	96	13	1,170	383	189	10	6	1,976	339	2,315	1	2,316
2029	87	11	8	105	103	14	1,250	382	204	11	6	2,075	418	2,492	1	2,493
2030	85	11	8	103	106	14	1,329	382	226	11	7	2,179	503	2,681	1	2,682
2031	82	10	8	101	113	16	1,397	382	248	12	6	2,274	573	2,848	0	2,848
2032	80	10	8	98	116	16	1,455	383	260	12	6	2,347	653	3,000	0	3,001
2033	78	10	8	96	122	17	1,461	382	279	13	6	2,377	731	3,108	0	3,108
2034	76	9	9	93	234	61	1,465	462	282	19	3	2,620	757	3,377	0	3,378
2035	73	9	9	91	303	364	1,513	522	296	24	2	3,114	815	3,929	0	3,930
2036	71	9	9	89	305	357	1,536	535	316	25	2	3,164	993	4,158	0	4,158
2037	69	8	9	87	304	349	1,656	545	355	27	2	3,323	1,171	4,494	0	4,494
2038	73	8	9	91	321	343	1,749	573	374	29	2	3,481	1,353	4,833	0	4,834
2039	70	8	10	88	329	337	1,808	594	414	30	2	3,602	1,546	5,148	0	5,149
2040	67	8	10	85	331	330	1,880	609	422	32	2	3,689	1,733	5,423	0	5,423
2041	65	7	10	82	329	322	1,977	619	448	33	2	3,812	1,932	5,744	0	5,745
2042	62	7	10	80	403	354	2,009	697	455	40	2	4,038	2,081	6,120	0	6,120
2043	59	7	11	77	449	674	2,032	752	476	45	2	4,507	2,252	6,759	0	6,760
2044	57	7	11	75	461	659	2,138	785	491	47	2	4,659	2,467	7,126	0	7,126
2045	55	7	11	73	478	646	2,254	825	519	51	2	4,847	2,663	7,511	1	7,511
2046	53	7	11	71	485	631	2,362	855	536	53	2	4,995	2,879	7,874	0	7,874
2047	50	6	12	68	478	614	2,390	867	565	55	2	5,041	3,054	8,095	0	8,096
2048	48	6	12	66	465	595	2,447	867	582	57	2	5,081	3,248	8,329	0	8,330
2049	46	6	12	64	448	576	2,446	867	605	56	2	5,065	3,421	8,486	0	8,487
2050	44	6	13	62	426	557	2,498	867	624	51	2	5,088	3,645	8,733	0	8,734
2051	45	6	13	64	405	538	2,580	867	669	48	2	5,173	3,854	9,026	1	9,027
2052	39	5	11	54	378	519	2,684	867	670	45	2	5,221	4,101	9,322	0	9,323
2053	24	2	5	31	366	501	2,776	867	702	46	2	5,291	4,326	9,616	0	9,617
Nominal $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	INCR. O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total

Low Fuel with Carbon Case

Nominal $M	CEC Units				Remainder of System							Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	Nominal $M
	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions						
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2020
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2021
2022	27	3	1	31	-	-	(8)	-	(1)	(0)	(0)	21	-	21	1	22	2022
2023	76	8	4	87	-	-	(24)	-	(4)	0	(0)	59	-	59	1	60	2023
2024	119	13	6	138	-	-	(48)	-	(5)	0	(0)	85	-	85	1	86	2024
2025	113	12	6	131	-	-	(47)	-	(5)	0	(0)	79	(5)	75	1	75	2025
2026	107	12	7	125	-	-	(50)	-	(5)	0	(0)	71	(8)	63	1	63	2026
2027	94	11	7	112	(9)	(2)	(52)	-	(5)	(0)	(0)	44	(11)	33	1	34	2027
2028	90	11	7	109	(25)	(4)	(51)	-	(6)	(1)	0	22	(14)	9	1	9	2028
2029	87	11	8	105	(21)	(3)	(59)	-	(7)	(1)	0	14	(15)	(1)	1	(0)	2029
2030	85	11	8	103	(23)	(4)	(54)	-	(7)	(1)	0	14	(17)	(3)	1	(2)	2030
2031	82	10	8	101	(20)	(3)	(64)	-	(6)	(1)	0	7	(21)	(14)	0	(13)	2031
2032	80	10	8	98	(22)	(4)	(60)	-	(8)	(1)	0	4	(23)	(19)	0	(19)	2032
2033	78	10	8	96	(18)	(3)	(62)	-	(5)	(1)	0	6	(28)	(22)	0	(22)	2033
2034	76	9	9	93	(23)	(4)	(67)	(26)	(7)	(2)	(0)	(36)	(35)	(71)	0	(71)	2034
2035	73	9	9	91	(32)	(6)	(64)	(44)	(7)	(2)	(0)	(64)	(35)	(99)	0	(99)	2035
2036	71	9	9	89	(19)	(4)	(65)	(31)	(5)	(2)	(0)	(36)	(42)	(78)	0	(77)	2036
2037	69	8	9	87	(10)	(2)	(72)	(21)	(3)	(1)	(0)	(22)	(50)	(72)	0	(72)	2037
2038	73	8	9	91	(22)	(4)	(73)	(35)	(7)	(2)	(0)	(52)	(57)	(109)	0	(109)	2038
2039	70	8	10	88	(29)	(6)	(77)	(45)	(7)	(3)	(0)	(79)	(67)	(146)	0	(145)	2039
2040	67	8	10	85	(28)	(5)	(80)	(45)	(6)	(3)	(0)	(83)	(74)	(157)	0	(156)	2040
2041	65	7	10	82	(27)	(5)	(82)	(45)	(7)	(3)	(0)	(88)	(81)	(169)	0	(168)	2041
2042	62	7	10	80	(27)	(5)	(80)	(45)	(7)	(3)	(0)	(88)	(84)	(171)	0	(171)	2042
2043	59	7	11	77	(26)	(5)	(84)	(45)	(8)	(3)	(0)	(93)	(92)	(185)	0	(185)	2043
2044	57	7	11	75	(25)	(5)	(82)	(45)	(6)	(3)	(0)	(91)	(94)	(186)	0	(185)	2044
2045	55	7	11	73	(24)	(5)	(87)	(45)	(8)	(3)	(0)	(100)	(102)	(202)	1	(202)	2045
2046	53	7	11	71	(10)	(2)	(88)	(28)	(8)	(2)	(0)	(68)	(106)	(175)	0	(174)	2046
2047	50	6	12	68	(1)	(0)	(86)	(16)	(4)	(2)	(0)	(41)	(109)	(150)	0	(150)	2047
2048	48	6	12	66	(1)	(0)	(94)	(16)	(8)	(2)	(0)	(54)	(123)	(177)	0	(177)	2048
2049	46	6	12	64	(1)	(0)	(87)	(16)	(7)	(2)	(0)	(48)	(121)	(169)	0	(169)	2049
2050	44	6	13	62	(1)	(0)	(89)	(16)	(8)	(2)	(0)	(53)	(128)	(181)	0	(181)	2050
2051	45	6	13	64	(1)	(0)	(96)	(16)	6	(2)	(0)	(44)	(144)	(188)	1	(188)	2051
2052	39	5	11	54	(0)	(0)	(81)	(16)	(6)	(2)	(0)	(51)	(123)	(175)	0	(174)	2052
2053	24	2	5	31	(0)	(0)	(42)	(16)	(5)	(2)	(0)	(34)	(65)	(99)	0	(98)	2053
CPVRR $M	Generation	Transmission	O&M	Total	Generation	Transmission	Fuel	Gas Reservation	Start Up & VOM	O&M	Non Carbon Emissions	Without Carbon Emissions Total	Carbon Emissions Related	With Carbon System Total	Admin Fees	System Total	CPVRR $M

Low Fuel

	System Benefits and CEC Program Impacts (Nominal $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	21.1	0.6	(15.0)	14.9	21.6
2023	58.9	0.7	(45.0)	44.6	59.1
2024	85.1	0.7	(75.0)	74.3	85.0
2025	74.7	0.7	(75.0)	74.8	75.2
2026	62.6	0.5	(75.0)	75.6	63.6
2027	83.5	0.6	(75.0)	76.3	85.2
2028	8.8	0.5	(75.0)	77.2	11.4
2029	(0.7)	0.5	(75.0)	77.7	2.6
2030	(2.8)	0.6	(75.0)	78.5	1.4
2031	(13.6)	0.4	(75.0)	79.2	(9.0)
2032	(19.2)	0.4	(75.0)	80.1	(13.8)
2033	(22.1)	0.4	(75.0)	80.7	(16.0)
2034	(71.0)	0.4	(75.0)	81.5	(64.1)
2035	(99.5)	0.4	(75.0)	82.3	(91.8)
2036	(77.5)	0.4	(75.0)	83.2	(68.9)
2037	(72.1)	0.4	(75.0)	83.8	(62.9)
2038	(109.4)	0.4	(75.0)	84.6	(99.4)
2039	(146.0)	0.5	(75.0)	85.5	(135.1)
2040	(156.8)	0.4	(75.0)	86.5	(144.9)
2041	(168.6)	0.4	(75.0)	87.1	(156.1)
2042	(171.2)	0.5	(75.0)	88.0	(157.8)
2043	(185.0)	0.5	(75.0)	88.8	(170.8)
2044	(185.7)	0.5	(75.0)	89.9	(170.4)
2045	(202.1)	0.5	(75.0)	90.5	(186.1)
2046	(174.7)	0.4	(75.0)	91.4	(157.9)
2047	(150.3)	0.5	(75.0)	92.3	(132.5)
2048	(177.0)	0.5	(75.0)	93.3	(158.2)
2049	(169.0)	0.5	(75.0)	94.1	(149.5)
2050	(181.4)	0.5	(75.0)	95.0	(161.0)
2051	(188.4)	0.5	(75.0)	95.9	(167.0)
2052	(174.7)	0.5	(60.0)	76.6	(157.6)
2053	(98.9)	0.5	(30.0)	38.0	(90.4)

	System Benefits and CEC Program Impacts (PV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.5	0.6	(14.2)	14.1	19.0
2023	48.5	0.6	(37.1)	36.7	48.7
2024	65.6	0.5	(57.9)	57.3	65.6
2025	54.0	0.5	(54.3)	54.1	54.4
2026	42.4	0.3	(50.9)	51.2	43.1
2027	21.2	0.4	(47.7)	48.4	22.4
2028	5.2	0.3	(44.7)	45.9	6.8
2029	(0.4)	0.3	(41.9)	43.4	1.4
2030	(1.4)	0.3	(39.2)	41.0	0.7
2031	(6.6)	0.2	(36.8)	38.8	(4.4)
2032	(8.8)	0.2	(34.5)	36.8	(6.3)
2033	(9.5)	0.2	(32.3)	34.7	(6.9)
2034	(28.6)	0.2	(30.3)	32.9	(25.9)
2035	(37.6)	0.2	(28.4)	31.1	(34.7)
2036	(27.5)	0.2	(26.6)	29.5	(24.4)
2037	(23.9)	0.1	(24.9)	27.8	(20.9)
2038	(34.1)	0.1	(23.4)	26.3	(30.9)
2039	(42.6)	0.1	(21.9)	24.9	(39.4)
2040	(42.9)	0.1	(20.5)	23.6	(39.6)
2041	(43.2)	0.1	(19.2)	22.3	(40.0)
2042	(41.1)	0.1	(18.0)	21.1	(37.9)
2043	(41.6)	0.1	(16.9)	20.0	(38.4)
2044	(39.2)	0.1	(15.8)	18.9	(35.9)
2045	(39.9)	0.1	(14.8)	17.9	(36.8)
2046	(32.4)	0.1	(13.9)	16.9	(29.2)
2047	(26.1)	0.1	(13.0)	16.0	(23.0)
2048	(28.8)	0.1	(12.2)	15.2	(25.7)
2049	(25.3)	0.1	(11.4)	14.3	(22.3)
2050	(25.9)	0.1	(10.7)	13.6	(23.0)
2051	(25.2)	0.1	(10.1)	12.8	(22.4)
2052	(21.9)	0.1	(7.5)	9.6	(19.8)
2053	(11.6)	0.1	(3.5)	4.5	(10.6)

	System Benefits and CEC Program Impacts (CPV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.5	1.5	(14.2)	14.1	19.9
2023	67.0	2.1	(51.3)	49.8	68.6
2024	132.7	2.6	(108.2)	107.1	134.2
2025	186.7	3.1	(162.4)	161.2	188.6
2026	229.1	3.4	(213.3)	212.4	231.7
2027	250.4	3.8	(260.9)	260.8	254.0
2028	255.6	4.1	(305.6)	306.8	260.8
2029	255.2	4.4	(347.5)	350.1	262.3
2030	253.9	4.7	(386.7)	391.2	264.0
2031	247.2	4.9	(423.5)	430.0	258.6
2032	238.4	5.0	(458.0)	466.8	252.2
2033	228.9	5.2	(490.3)	501.5	245.4
2034	200.2	5.4	(520.5)	534.4	219.5
2035	162.6	5.5	(548.9)	565.5	184.8
2036	135.2	5.7	(575.5)	595.0	160.4
2037	111.2	5.8	(600.4)	622.8	139.5
2038	77.2	6.0	(623.8)	649.2	108.5
2039	34.6	6.1	(645.7)	674.1	69.1
2040	(8.3)	6.2	(666.2)	697.7	29.5
2041	(51.4)	6.3	(685.4)	720.1	(10.5)
2042	(92.6)	6.4	(703.4)	741.2	(48.4)
2043	(134.2)	6.5	(720.3)	761.2	(86.8)
2044	(173.3)	6.6	(736.1)	780.1	(122.7)
2045	(213.3)	6.7	(751.0)	798.0	(159.5)
2046	(245.6)	6.8	(764.9)	814.9	(188.7)
2047	(271.7)	6.9	(777.9)	830.9	(211.8)
2048	(300.5)	7.0	(790.1)	846.1	(237.5)
2049	(326.3)	7.1	(801.6)	860.5	(260.3)
2050	(352.2)	7.1	(812.3)	874.0	(283.3)
2051	(377.4)	7.2	(822.3)	886.9	(305.7)
2052	(399.4)	7.3	(829.9)	896.5	(325.5)
2053	(411.0)	7.3	(833.4)	901.0	(336.1)

Mid Fuel

	System Benefits and CEC Program Impacts (Nominal $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	21.1	0.6	(15.0)	14.9	21.6
2023	58.9	0.7	(45.0)	44.6	59.2
2024	84.3	0.7	(75.0)	74.3	84.2
2025	73.2	0.7	(75.0)	74.8	73.7
2026	60.6	0.5	(75.0)	75.6	61.6
2027	27.9	0.6	(75.0)	76.3	29.7
2028	1.6	0.5	(75.0)	77.2	4.2
2029	(12.2)	0.5	(75.0)	77.7	(8.9)
2030	(11.7)	0.6	(75.0)	78.5	(7.7)
2031	(25.5)	0.4	(75.0)	79.2	(21.0)
2032	(31.0)	0.4	(75.0)	80.1	(25.5)
2033	(33.7)	0.4	(75.0)	80.7	(27.6)
2034	(80.8)	0.4	(75.0)	81.5	(74.0)
2035	(112.7)	0.4	(75.0)	82.3	(105.1)
2036	(91.7)	0.4	(75.0)	83.2	(83.0)
2037	(88.4)	0.4	(75.0)	83.8	(79.2)
2038	(126.3)	0.4	(75.0)	84.6	(116.3)
2039	(164.0)	0.5	(75.0)	85.5	(153.1)
2040	(176.6)	0.4	(75.0)	86.5	(164.7)
2041	(188.0)	0.4	(75.0)	87.1	(175.5)
2042	(191.4)	0.5	(75.0)	88.0	(178.0)
2043	(206.9)	0.5	(75.0)	88.8	(192.7)
2044	(207.5)	0.5	(75.0)	89.9	(192.3)
2045	(225.6)	0.5	(75.0)	90.5	(209.6)
2046	(199.4)	0.4	(75.0)	91.4	(182.6)
2047	(174.8)	0.5	(75.0)	92.3	(157.1)
2048	(205.6)	0.5	(75.0)	93.3	(186.8)
2049	(197.6)	0.5	(75.0)	94.1	(178.1)
2050	(210.5)	0.5	(75.0)	95.0	(190.1)
2051	(220.5)	0.5	(75.0)	95.9	(199.1)
2052	(201.6)	0.5	(60.0)	76.6	(184.5)
2053	(113.0)	0.5	(30.0)	38.0	(104.5)

	System Benefits and CEC Program Impacts (PV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.5	0.6	(13.2)	13.1	18.9
2023	48.5	0.6	(37.1)	36.7	48.7
2024	65.0	0.5	(57.9)	57.3	65.0
2025	52.9	0.5	(54.3)	54.1	53.3
2026	41.1	0.3	(50.9)	51.2	41.7
2027	17.7	0.4	(47.7)	48.4	18.9
2028	0.9	0.3	(44.7)	45.9	2.5
2029	(6.8)	0.3	(41.9)	43.4	(5.0)
2030	(6.1)	0.3	(39.2)	41.0	(4.1)
2031	(12.5)	0.2	(36.8)	38.8	(10.3)
2032	(14.2)	0.2	(34.5)	36.8	(11.7)
2033	(14.5)	0.2	(32.3)	34.7	(11.9)
2034	(32.6)	0.2	(30.3)	32.9	(29.8)
2035	(42.6)	0.2	(28.4)	31.1	(39.7)
2036	(32.5)	0.2	(26.6)	29.5	(29.4)
2037	(29.4)	0.1	(24.9)	27.8	(26.3)
2038	(39.3)	0.1	(23.4)	26.3	(36.2)
2039	(47.8)	0.1	(21.9)	24.9	(44.7)
2040	(48.3)	0.1	(20.5)	23.6	(45.0)
2041	(48.2)	0.1	(19.2)	22.3	(45.0)
2042	(46.0)	0.1	(18.0)	21.1	(42.7)
2043	(46.6)	0.1	(16.9)	20.0	(43.4)
2044	(43.8)	0.1	(15.8)	18.9	(40.5)
2045	(44.6)	0.1	(14.8)	17.9	(41.4)
2046	(36.9)	0.1	(13.9)	16.9	(33.8)
2047	(30.3)	0.1	(13.0)	16.0	(27.3)
2048	(33.4)	0.1	(12.2)	15.2	(30.4)
2049	(30.1)	0.1	(11.4)	14.3	(27.2)
2050	(30.1)	0.1	(10.7)	13.6	(27.2)
2051	(29.5)	0.1	(10.1)	12.8	(26.7)
2052	(25.3)	0.1	(7.5)	9.6	(23.2)
2053	(13.3)	0.1	(3.5)	4.5	(12.3)

	System Benefits and CEC Program Impacts (CPV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.5	1.5	(13.2)	13.1	19.9
2023	67.0	2.1	(50.3)	49.8	68.6
2024	132.1	2.6	(108.2)	107.1	133.6
2025	185.0	3.1	(162.4)	161.2	186.8
2026	226.0	3.4	(213.3)	212.4	228.6
2027	243.8	3.8	(260.9)	260.8	247.5
2028	244.7	4.1	(305.6)	306.8	250.0
2029	237.9	4.4	(347.5)	350.1	245.0
2030	231.8	4.7	(386.7)	391.2	240.9
2031	219.3	4.9	(423.5)	430.0	230.6
2032	205.0	5.0	(458.0)	466.8	218.9
2033	190.5	5.2	(490.3)	501.5	207.0
2034	157.9	5.4	(520.5)	534.4	177.2
2035	115.3	5.5	(548.9)	565.5	137.5
2036	82.9	5.7	(575.5)	595.0	108.0
2037	53.5	5.8	(600.4)	622.8	81.7
2038	14.2	6.0	(623.8)	649.2	45.6
2039	(33.6)	6.1	(645.7)	674.1	0.9
2040	(81.9)	6.2	(666.2)	697.7	(44.1)
2041	(130.1)	6.3	(685.4)	720.1	(89.1)
2042	(176.0)	6.4	(703.4)	741.2	(131.8)
2043	(222.6)	6.5	(720.3)	761.2	(175.2)
2044	(266.4)	6.6	(736.1)	780.1	(215.8)
2045	(311.0)	6.7	(751.0)	798.0	(257.2)
2046	(347.9)	6.8	(764.9)	814.9	(291.0)
2047	(378.3)	6.9	(777.9)	830.9	(318.3)
2048	(411.7)	7.0	(790.1)	846.1	(348.7)
2049	(441.8)	7.1	(801.6)	860.5	(375.8)
2050	(471.9)	7.1	(812.3)	874.0	(403.0)
2051	(501.5)	7.2	(822.3)	886.9	(429.7)
2052	(526.8)	7.3	(829.9)	896.5	(452.9)
2053	(540.1)	7.3	(833.4)	901.0	(465.1)

High Fuel

	System Benefits and CEC Program Impacts (Nominal $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	20.6	0.6	(15.0)	14.9	21.1
2023	54.2	0.7	(45.0)	44.6	54.4
2024	72.1	0.7	(75.0)	74.3	72.0
2025	59.3	0.7	(75.0)	74.8	59.7
2026	44.7	0.5	(75.0)	75.6	45.7
2027	11.8	0.6	(75.0)	76.3	13.5
2028	(15.7)	0.5	(75.0)	77.2	(13.1)
2029	(28.4)	0.5	(75.0)	77.7	(25.2)
2030	(32.1)	0.6	(75.0)	78.5	(28.1)
2031	(51.4)	0.4	(75.0)	79.2	(46.8)
2032	(54.8)	0.4	(75.0)	80.1	(49.3)
2033	(57.7)	0.4	(75.0)	80.7	(51.6)
2034	(108.1)	0.4	(75.0)	81.5	(101.3)
2035	(141.1)	0.4	(75.0)	82.3	(133.4)
2036	(120.7)	0.4	(75.0)	83.2	(112.1)
2037	(121.6)	0.4	(75.0)	83.8	(112.4)
2038	(162.5)	0.4	(75.0)	84.6	(152.5)
2039	(200.2)	0.5	(75.0)	85.5	(189.3)
2040	(217.8)	0.4	(75.0)	86.5	(205.9)
2041	(233.1)	0.4	(75.0)	87.1	(220.5)
2042	(235.8)	0.5	(75.0)	88.0	(222.4)
2043	(254.3)	0.5	(75.0)	88.8	(240.1)
2044	(250.6)	0.5	(75.0)	89.9	(235.3)
2045	(271.9)	0.5	(75.0)	90.5	(255.9)
2046	(248.7)	0.4	(75.0)	91.4	(231.9)
2047	(226.7)	0.5	(75.0)	92.3	(209.0)
2048	(263.4)	0.5	(75.0)	93.3	(244.6)
2049	(251.8)	0.5	(75.0)	94.1	(232.3)
2050	(268.7)	0.5	(75.0)	95.0	(248.3)
2051	(284.5)	0.5	(75.0)	95.9	(263.1)
2052	(255.1)	0.5	(60.0)	76.6	(238.0)
2053	(140.7)	0.5	(30.0)	38.0	(132.2)

	System Benefits and CEC Program Impacts (PV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.1	0.6	(13.2)	13.1	18.5
2023	44.6	0.6	(37.1)	36.7	44.8
2024	55.6	0.5	(57.9)	57.3	55.5
2025	42.9	0.5	(54.3)	54.1	43.2
2026	30.3	0.3	(50.9)	51.2	31.0
2027	7.5	0.4	(47.7)	48.4	8.6
2028	(9.4)	0.3	(44.7)	45.9	(7.8)
2029	(15.8)	0.3	(41.9)	43.4	(14.1)
2030	(16.8)	0.3	(39.2)	41.0	(14.7)
2031	(25.2)	0.2	(36.8)	38.8	(22.9)
2032	(25.2)	0.2	(34.5)	36.8	(22.6)
2033	(24.8)	0.2	(32.3)	34.7	(22.2)
2034	(43.6)	0.2	(30.3)	32.9	(40.9)
2035	(53.3)	0.2	(28.4)	31.1	(50.4)
2036	(42.8)	0.2	(26.6)	29.5	(39.7)
2037	(40.4)	0.1	(24.9)	27.8	(37.3)
2038	(50.6)	0.1	(23.4)	26.3	(47.5)
2039	(58.4)	0.1	(21.9)	24.9	(55.2)
2040	(59.5)	0.1	(20.5)	23.6	(56.3)
2041	(59.7)	0.1	(19.2)	22.3	(56.5)
2042	(56.6)	0.1	(18.0)	21.1	(53.4)
2043	(57.2)	0.1	(16.9)	20.0	(54.0)
2044	(52.8)	0.1	(15.8)	18.9	(49.6)
2045	(53.7)	0.1	(14.8)	17.9	(50.6)
2046	(46.1)	0.1	(13.9)	16.9	(43.0)
2047	(39.4)	0.1	(13.0)	16.0	(36.3)
2048	(42.9)	0.1	(12.2)	15.2	(39.8)
2049	(38.4)	0.1	(11.4)	14.3	(35.4)
2050	(38.4)	0.1	(10.7)	13.6	(35.5)
2051	(38.1)	0.1	(10.1)	12.8	(35.2)
2052	(32.0)	0.1	(7.5)	9.6	(29.9)
2053	(16.6)	0.1	(3.5)	4.5	(15.6)

	System Benefits and CEC Program Impacts (CPV $)				
$M	Net System Savings	DEF CEC Program Admin Costs	DEF CEC Subscription Fee	DEF CEC Bill Credits	Remaining Net System Savings
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	1.0	0.0	0.0	1.0
2022	18.1	1.5	(13.2)	13.1	19.5
2023	62.7	2.1	(50.3)	49.8	64.3
2024	118.3	2.6	(108.2)	107.1	119.8
2025	161.2	3.1	(162.4)	161.2	163.0
2026	191.4	3.4	(213.3)	212.4	194.0
2027	198.9	3.8	(260.9)	260.8	202.6
2028	189.6	4.1	(305.6)	306.8	194.8
2029	173.7	4.4	(347.5)	350.1	180.8
2030	156.9	4.7	(386.7)	391.2	166.1
2031	131.8	4.9	(423.5)	430.0	143.1
2032	106.6	5.0	(458.0)	466.8	120.5
2033	81.8	5.2	(490.3)	501.5	98.3
2034	38.2	5.4	(520.5)	534.4	57.4
2035	(15.2)	5.5	(548.9)	565.5	7.0
2036	(57.9)	5.7	(575.5)	595.0	(32.7)
2037	(98.3)	5.8	(600.4)	622.8	(70.1)
2038	(148.9)	6.0	(623.8)	649.2	(117.5)
2039	(207.3)	6.1	(645.7)	674.1	(172.7)
2040	(266.8)	6.2	(666.2)	697.7	(229.0)
2041	(326.5)	6.3	(685.4)	720.1	(285.5)
2042	(383.1)	6.4	(703.4)	741.2	(338.9)
2043	(440.3)	6.5	(720.3)	761.2	(392.9)
2044	(493.2)	6.6	(736.1)	780.1	(442.6)
2045	(546.9)	6.7	(751.0)	798.0	(493.1)
2046	(593.0)	6.8	(764.9)	814.9	(536.1)
2047	(632.3)	6.9	(777.9)	830.9	(572.4)
2048	(675.2)	7.0	(790.1)	846.1	(612.2)
2049	(713.6)	7.1	(801.6)	860.5	(647.6)
2050	(752.0)	7.1	(812.3)	874.0	(683.1)
2051	(790.1)	7.2	(822.3)	886.9	(718.3)
2052	(822.1)	7.3	(829.9)	896.5	(748.2)
2053	(838.7)	7.3	(833.4)	901.0	(763.8)

Low Fuel

	System Benefits and CEC Program Impacts (Nominal $)			Total Billed	Monthly Bill Impact ($/1,000 kWh)		
$M	Base *	Clause	Remaining Net System Savings	MWh	Base	Clause	Remaining Net System Savings
2021	0.0	0.0	0.0	39,857,384	0.00	0.00	0.00
2022	29.5	(8.4)	21.1	40,227,760	0.73	(0.21)	0.52
2023	83.2	(24.3)	58.9	40,513,294	2.05	(0.60)	1.45
2024	133.3	(48.3)	85.1	40,703,718	3.28	(1.19)	2.09
2025	126.6	(51.9)	74.7	41,205,631	3.07	(1.26)	1.81
2026	120.6	(58.0)	62.6	41,188,409	2.93	(1.41)	1.52
2027	96.5	(63.0)	33.5	41,513,413	2.32	(1.52)	0.81
2028	72.8	(64.1)	8.8	42,152,270	1.73	(1.52)	0.21
2029	73.2	(73.9)	(0.7)	42,481,081	1.72	(1.74)	(0.02)
2030	67.7	(70.4)	(2.6)	42,694,826	1.59	(1.65)	(0.06)
2031	70.3	(83.9)	(13.6)	43,306,946	1.62	(1.94)	(0.31)
2032	64.0	(83.2)	(19.2)	43,305,627	1.48	(1.92)	(0.44)
2033	68.1	(90.2)	(22.1)	44,128,573	1.54	(2.04)	(0.50)
2034	57.1	(128.1)	(71.0)	44,458,159	1.28	(2.88)	(1.60)
2035	44.3	(143.8)	(99.5)	44,917,813	0.99	(3.20)	(2.21)
2036	59.7	(137.3)	(77.5)	45,464,126	1.31	(3.02)	(1.71)
2037	70.7	(142.8)	(72.1)	45,732,122	1.55	(3.12)	(1.58)
2038	56.1	(165.6)	(109.4)	46,200,854	1.21	(3.58)	(2.37)
2039	43.5	(189.5)	(146.0)	46,789,936	0.93	(4.05)	(3.12)
2040	42.1	(198.8)	(156.8)	47,259,984	0.89	(4.21)	(3.32)
2041	40.1	(208.7)	(168.6)	47,721,196	0.84	(4.37)	(3.53)
2042	38.1	(209.3)	(171.2)	48,407,906	0.79	(4.32)	(3.54)
2043	35.8	(220.8)	(185.0)	48,611,413	0.74	(4.54)	(3.81)
2044	36.3	(222.0)	(185.7)	49,059,789	0.74	(4.52)	(3.78)
2045	32.4	(234.5)	(202.1)	49,806,440	0.65	(4.71)	(4.06)
2046	47.9	(222.5)	(174.7)	50,128,610	0.95	(4.44)	(3.48)
2047	61.4	(211.7)	(150.2)	50,128,610	1.23	(4.22)	(3.00)
2048	56.0	(233.0)	(177.0)	50,245,691	1.11	(4.64)	(3.52)
2049	54.2	(223.2)	(169.0)	50,128,610	1.08	(4.45)	(3.37)
2050	51.9	(233.2)	(181.4)	50,128,610	1.03	(4.65)	(3.62)
2051	67.3	(255.6)	(188.4)	50,128,610	1.34	(5.10)	(3.76)
2052	45.6	(220.3)	(174.7)	50,245,691	0.91	(4.38)	(3.48)
2053	23.8	(122.7)	(98.9)	50,128,610	0.47	(2.45)	(1.97)

*Excludes program administration costs

Mid Fuel

	System Benefits and CEC Program Impacts (Nominal $)			Total Billed	Monthly Bill Impact ($/1,000 kWh)		
$M	Base *	Clause	Remaining Net System Savings	MWh	Base	Clause	Remaining Net System Savings
2021	0.0	0.0	0.0	39,857,384	0.00	0.00	0.00
2022	29.5	(8.4)	21.1	40,227,760	0.73	(0.21)	0.52
2023	83.2	(24.3)	58.9	40,513,294	2.05	(0.60)	1.45
2024	133.0	(48.7)	84.3	40,703,718	3.27	(1.20)	2.07
2025	126.9	(53.7)	73.2	41,205,631	3.08	(1.30)	1.78
2026	120.7	(60.1)	60.6	41,188,409	2.93	(1.46)	1.47
2027	96.3	(68.4)	27.9	41,513,413	2.32	(1.65)	0.67
2028	72.9	(71.4)	1.6	42,152,270	1.73	(1.69)	0.04
2029	75.0	(87.1)	(12.2)	42,481,081	1.77	(2.05)	(0.29)
2030	69.1	(80.9)	(11.7)	42,694,826	1.62	(1.89)	(0.28)
2031	70.1	(95.6)	(25.5)	43,306,946	1.62	(2.21)	(0.59)
2032	65.2	(96.2)	(31.0)	43,305,627	1.51	(2.22)	(0.72)
2033	67.8	(101.5)	(33.7)	44,128,573	1.54	(2.30)	(0.76)
2034	57.4	(138.2)	(80.8)	44,458,159	1.29	(3.11)	(1.82)
2035	44.3	(157.0)	(112.7)	44,917,813	0.99	(3.50)	(2.51)
2036	59.6	(151.3)	(91.7)	45,464,126	1.31	(3.33)	(2.02)
2037	70.9	(159.3)	(88.4)	45,732,122	1.55	(3.48)	(1.93)
2038	55.9	(182.1)	(126.3)	46,200,854	1.21	(3.94)	(2.73)
2039	43.4	(207.4)	(164.0)	46,789,936	0.93	(4.43)	(3.51)
2040	42.0	(218.5)	(176.6)	47,259,984	0.89	(4.62)	(3.74)
2041	40.1	(228.1)	(188.0)	47,721,196	0.84	(4.78)	(3.94)
2042	38.1	(229.5)	(191.4)	48,407,906	0.79	(4.74)	(3.95)
2043	35.9	(242.8)	(206.9)	48,611,413	0.74	(4.99)	(4.26)
2044	36.5	(244.1)	(207.5)	49,059,789	0.74	(4.98)	(4.23)
2045	32.7	(258.3)	(225.6)	49,806,440	0.66	(5.19)	(4.53)
2046	47.8	(247.2)	(199.4)	50,128,610	0.95	(4.93)	(3.98)
2047	61.6	(236.4)	(174.8)	50,128,610	1.23	(4.72)	(3.49)
2048	56.0	(261.6)	(205.6)	50,245,691	1.11	(5.21)	(4.09)
2049	54.2	(251.9)	(197.6)	50,128,610	1.08	(5.02)	(3.94)
2050	52.1	(262.6)	(210.5)	50,128,610	1.04	(5.24)	(4.20)
2051	67.2	(287.7)	(220.5)	50,128,610	1.34	(5.74)	(4.40)
2052	45.7	(247.3)	(201.6)	50,245,691	0.91	(4.92)	(4.01)
2053	23.9	(136.9)	(113.0)	50,128,610	0.48	(2.73)	(2.25)

*Excludes program administration costs

High Fuel

	System Benefits and CEC Program Impacts (Nominal $)			Total Billed	Monthly Bill Impact ($/1,000 kWh)		
$M	Base *	Clause	Remaining Net System Savings	MWh	Base	Clause	Remaining Net System Savings
2021	0.0	0.0	0.0	39,857,384	0.00	0.00	0.00
2022	29.5	(8.9)	20.6	40,227,760	0.73	(0.22)	0.51
2023	83.2	(29.0)	54.2	40,513,294	2.05	(0.72)	1.34
2024	133.7	(61.6)	72.1	40,703,718	3.28	(1.51)	1.77
2025	126.9	(67.6)	59.3	41,205,631	3.08	(1.64)	1.44
2026	120.8	(76.1)	44.7	41,188,409	2.93	(1.85)	1.08
2027	96.2	(84.5)	11.8	41,513,413	2.32	(2.03)	0.28
2028	72.6	(88.3)	(15.7)	42,152,270	1.72	(2.09)	(0.37)
2029	74.6	(103.0)	(28.4)	42,481,081	1.76	(2.42)	(0.67)
2030	69.3	(101.4)	(32.1)	42,694,826	1.62	(2.37)	(0.75)
2031	71.6	(122.9)	(51.4)	43,306,946	1.65	(2.84)	(1.19)
2032	65.6	(120.4)	(54.8)	43,305,627	1.52	(2.78)	(1.27)
2033	67.4	(125.2)	(57.7)	44,128,573	1.53	(2.84)	(1.31)
2034	57.4	(165.6)	(108.1)	44,458,159	1.29	(3.72)	(2.43)
2035	44.1	(185.2)	(141.1)	44,917,813	0.98	(4.12)	(3.14)
2036	60.0	(180.8)	(120.7)	45,464,126	1.32	(3.98)	(2.66)
2037	70.8	(192.4)	(121.6)	45,732,122	1.55	(4.21)	(2.66)
2038	55.5	(218.0)	(162.5)	46,200,854	1.20	(4.72)	(3.52)
2039	43.0	(243.2)	(200.2)	46,789,936	0.92	(5.20)	(4.28)
2040	41.4	(259.1)	(217.8)	47,259,984	0.88	(5.48)	(4.61)
2041	39.3	(272.4)	(233.1)	47,721,196	0.82	(5.71)	(4.88)
2042	38.1	(273.8)	(235.8)	48,407,906	0.79	(5.66)	(4.87)
2043	36.0	(290.4)	(254.3)	48,611,413	0.74	(5.97)	(5.23)
2044	36.9	(287.4)	(250.6)	49,059,789	0.75	(5.86)	(5.11)
2045	33.0	(304.9)	(271.9)	49,806,440	0.66	(6.12)	(5.46)
2046	47.7	(296.4)	(248.7)	50,128,610	0.95	(5.91)	(4.96)
2047	61.7	(288.4)	(226.7)	50,128,610	1.23	(5.75)	(4.52)
2048	56.1	(319.5)	(263.4)	50,245,691	1.12	(6.36)	(5.24)
2049	54.6	(306.3)	(251.8)	50,128,610	1.09	(6.11)	(5.02)
2050	52.5	(321.2)	(268.7)	50,128,610	1.05	(6.41)	(5.36)
2051	67.3	(351.8)	(284.5)	50,128,610	1.34	(7.02)	(5.67)
2052	45.8	(300.9)	(255.1)	50,245,691	0.91	(5.99)	(5.08)
2053	24.0	(164.7)	(140.7)	50,128,610	0.48	(3.29)	(2.81)

*Excludes program administration costs

20FL-CEC-002065 - 20FL-CEC-002068

Low Fuel

	System Benefits and CEC Program Impacts (Nominal $)					Total Billed	Monthly Bill Impact ($/1,000 kWh)					Participant - Excludes Low Income		Low Income Participant	
												Participant (Assumes 5kw)	Participant Monthly	Participant (Assumes 5kw)	Participant Monthly
$M	Base *	Clause	Subscription Fees	Bill Credits	Net Savings - General Body of Customers	MWh	Base	Clause	Susbscription Fees	Bill Credits	Net Savings - General Body of Customers	Subscription Net (Fee) / Credit	Bill Impact ($/1,000 kWh)	Subscription Net (Fee) / Credit	Bill Impact ($/1,000 kWh)
2021	1.0	0.0	0.0	0.0	1.0	39,857,384	**	0.00	0.00	0.00	**	0.00	**	0.00	**
2022	30.1	(8.4)	(15.0)	14.9	21.6	40,227,760	0.75	(0.21)	(0.37)	0.37	0.54	(0.49)	1.02	3.40	(2.86)
2023	83.9	(24.3)	(45.0)	44.6	59.1	40,513,294	2.07	(0.60)	(1.11)	1.10	1.46	(0.56)	2.02	3.40	(1.94)
2024	134.0	(48.3)	(75.0)	74.3	85.0	40,703,718	3.29	(1.19)	(1.84)	1.83	2.09	(0.56)	2.64	3.40	(1.31)
2025	127.3	(51.9)	(75.0)	74.8	75.2	41,205,631	3.09	(1.26)	(1.82)	1.82	1.82	(0.24)	2.07	3.40	(1.58)
2026	121.1	(58.0)	(75.0)	75.6	63.6	41,188,409	2.94	(1.41)	(1.82)	1.83	1.54	0.17	1.38	3.40	(1.86)
2027	97.0	(63.0)	(75.0)	76.3	35.2	41,513,413	2.34	(1.52)	(1.81)	1.84	0.85	0.58	0.27	3.40	(2.55)
2028	73.4	(64.1)	(75.0)	77.2	11.4	42,152,270	1.74	(1.52)	(1.78)	1.83	0.27	1.10	(0.83)	3.40	(3.13)
2029	73.7	(73.9)	(75.0)	77.7	2.6	42,481,081	1.74	(1.74)	(1.77)	1.83	0.06	1.42	(1.36)	3.40	(3.34)
2030	68.3	(70.4)	(75.0)	78.5	1.4	42,694,826	1.60	(1.65)	(1.76)	1.84	0.03	1.84	(1.81)	3.40	(3.37)
2031	70.7	(83.9)	(75.0)	79.2	(9.0)	43,306,946	1.63	(1.94)	(1.73)	1.83	(0.21)	2.27	(2.48)	3.40	(3.61)
2032	64.4	(83.2)	(75.0)	80.1	(13.8)	43,305,627	1.49	(1.92)	(1.73)	1.85	(0.32)	2.82	(3.13)	3.40	(3.72)
2033	68.5	(90.2)	(75.0)	80.7	(16.0)	44,128,573	1.55	(2.04)	(1.70)	1.83	(0.36)	3.15	(3.51)	3.40	(3.76)
2034	57.5	(128.1)	(75.0)	81.5	(64.1)	44,458,159	1.29	(2.88)	(1.69)	1.83	(1.44)	3.59	(5.04)	3.40	(4.84)
2035	44.7	(143.8)	(75.0)	82.3	(91.8)	44,917,813	1.00	(3.20)	(1.67)	1.83	(2.04)	4.04	(6.09)	3.40	(5.44)
2036	60.2	(137.3)	(75.0)	83.2	(68.9)	45,464,126	1.32	(3.02)	(1.65)	1.83	(1.52)	4.60	(6.12)	3.40	(4.92)
2037	71.1	(142.8)	(75.0)	83.8	(62.9)	45,732,122	1.56	(3.12)	(1.64)	1.83	(1.37)	4.95	(6.32)	3.40	(4.77)
2038	56.5	(165.6)	(75.0)	84.6	(99.4)	46,200,854	1.22	(3.58)	(1.62)	1.83	(2.15)	5.41	(7.56)	3.40	(5.55)
2039	44.0	(189.5)	(75.0)	85.5	(135.1)	46,789,936	0.94	(4.05)	(1.60)	1.83	(2.89)	5.88	(8.77)	3.40	(6.29)
2040	42.5	(198.8)	(75.0)	86.5	(144.9)	47,259,984	0.90	(4.21)	(1.59)	1.83	(3.07)	6.47	(9.54)	3.40	(6.47)
2041	40.5	(208.7)	(75.0)	87.1	(156.1)	47,721,196	0.85	(4.37)	(1.57)	1.83	(3.27)	6.83	(10.11)	3.40	(6.67)
2042	38.6	(209.3)	(75.0)	88.0	(157.8)	48,407,906	0.80	(4.32)	(1.55)	1.82	(3.26)	7.32	(10.58)	3.40	(6.66)
2043	36.2	(220.8)	(75.0)	88.8	(170.8)	48,611,413	0.75	(4.54)	(1.54)	1.83	(3.51)	7.80	(11.32)	3.40	(6.91)
2044	36.8	(222.0)	(75.0)	89.9	(170.4)	49,059,789	0.75	(4.52)	(1.53)	1.83	(3.47)	8.41	(11.88)	3.40	(6.87)
2045	33.0	(234.5)	(75.0)	90.5	(186.1)	49,806,440	0.66	(4.71)	(1.51)	1.82	(3.74)	8.79	(12.53)	3.40	(7.14)
2046	48.3	(222.5)	(75.0)	91.4	(157.9)	50,128,610	0.96	(4.44)	(1.50)	1.82	(3.15)	9.30	(12.45)	3.40	(6.55)
2047	61.9	(211.7)	(75.0)	92.3	(132.5)	50,128,610	1.24	(4.22)	(1.50)	1.84	(2.64)	9.80	(12.45)	3.40	(6.04)
2048	56.5	(233.0)	(75.0)	93.3	(158.2)	50,245,691	1.12	(4.64)	(1.49)	1.86	(3.15)	10.42	(13.57)	3.40	(6.55)
2049	54.7	(223.2)	(75.0)	94.1	(149.5)	50,128,610	1.09	(4.45)	(1.50)	1.88	(2.98)	10.83	(13.82)	3.40	(6.38)
2050	52.4	(233.2)	(75.0)	95.0	(161.0)	50,128,610	1.04	(4.65)	(1.50)	1.89	(3.21)	11.36	(14.57)	3.40	(6.61)
2051	67.8	(255.6)	(75.0)	95.9	(167.0)	50,128,610	1.35	(5.10)	(1.50)	1.91	(3.33)	11.88	(15.22)	3.40	(6.73)
2052	46.1	(220.3)	(60.0)	76.6	(157.6)	50,245,691	0.92	(4.38)	(1.19)	1.52	(3.14)	11.80	(14.94)	3.40	(6.54)
2053	24.3	(122.7)	(30.0)	38.0	(90.4)	50,128,610	0.48	(2.45)	(0.60)	0.76	(1.80)	11.43	(13.24)	3.40	(5.20)

* Includes program administration costs

** No rate impact in 2021 due to 2017 Settlement Agreement

Mid Fuel

	System Benefits and CEC Program Impacts (Nominal $)					Total Billed	Monthly Bill Impact ($/1,000 kWh)					Participant - Excludes Low Income		Low Income Participant	
$M	Base *	Clause	Subscription Fees	Bill Credits	Net Savings - General Body of Customers	MWh	Base	Clause	Susbscription Fees	Bill Credits	Net Savings - General Body of Customers	Participant (Assumes 5kw) Subscription Net (Fee) / Credit	Participant Monthly Bill Impact ($/1,000 kWh)	Participant (Assumes 5kw) Subscription Net (Fee) / Credit	Participant Monthly Bill Impact ($/1,000 kWh)
2021	1.0	0.0	0.0	0.0	1.0	39,857,384	**	0.00	0.00	0.00	**	0.00	**	0.00	**
2022	30.1	(8.4)	(15.0)	14.9	21.6	40,227,760	0.75	(0.21)	(0.37)	0.37	0.54	(0.49)	1.02	3.40	(2.86)
2023	83.9	(24.3)	(45.0)	44.6	59.2	40,513,294	2.07	(0.60)	(1.11)	1.10	1.46	(0.56)	2.02	3.40	(1.94)
2024	133.6	(48.7)	(75.0)	74.3	84.2	40,703,718	3.28	(1.20)	(1.84)	1.83	2.07	(0.56)	2.62	3.40	(1.33)
2025	127.6	(53.7)	(75.0)	74.8	73.7	41,205,631	3.10	(1.30)	(1.82)	1.82	1.79	(0.24)	2.03	3.40	(1.61)
2026	121.2	(60.1)	(75.0)	75.6	61.6	41,188,409	2.94	(1.46)	(1.82)	1.83	1.50	0.17	1.33	3.40	(1.90)
2027	96.9	(68.4)	(75.0)	76.3	29.7	41,513,413	2.33	(1.65)	(1.81)	1.84	0.72	0.58	0.14	3.40	(2.68)
2028	73.5	(71.4)	(75.0)	77.2	4.2	42,152,270	1.74	(1.69)	(1.78)	1.83	0.10	1.10	(1.00)	3.40	(3.30)
2029	75.5	(87.1)	(75.0)	77.7	(8.9)	42,481,081	1.78	(2.05)	(1.77)	1.83	(0.21)	1.42	(1.63)	3.40	(3.61)
2030	69.7	(80.9)	(75.0)	78.5	(7.7)	42,694,826	1.63	(1.89)	(1.76)	1.84	(0.18)	1.84	(2.03)	3.40	(3.58)
2031	70.5	(95.6)	(75.0)	79.2	(21.0)	43,306,946	1.63	(2.21)	(1.73)	1.83	(0.48)	2.27	(2.76)	3.40	(3.88)
2032	65.5	(96.2)	(75.0)	80.1	(25.5)	43,305,627	1.51	(2.22)	(1.73)	1.85	(0.59)	2.82	(3.40)	3.40	(3.99)
2033	68.2	(101.5)	(75.0)	80.7	(27.6)	44,128,573	1.55	(2.30)	(1.70)	1.83	(0.63)	3.15	(3.77)	3.40	(4.03)
2034	57.7	(138.2)	(75.0)	81.5	(74.0)	44,458,159	1.30	(3.11)	(1.69)	1.83	(1.66)	3.59	(5.26)	3.40	(5.06)
2035	44.7	(157.0)	(75.0)	82.3	(105.1)	44,917,813	1.00	(3.50)	(1.67)	1.83	(2.34)	4.04	(6.38)	3.40	(5.74)
2036	60.0	(151.3)	(75.0)	83.2	(83.0)	45,464,126	1.32	(3.33)	(1.65)	1.83	(1.83)	4.60	(6.43)	3.40	(5.23)
2037	71.3	(159.3)	(75.0)	83.8	(79.2)	45,732,122	1.56	(3.48)	(1.64)	1.83	(1.73)	4.95	(6.68)	3.40	(5.13)
2038	56.3	(182.1)	(75.0)	84.6	(116.3)	46,200,854	1.22	(3.94)	(1.62)	1.83	(2.52)	5.41	(7.92)	3.40	(5.92)
2039	43.9	(207.4)	(75.0)	85.5	(153.1)	46,789,936	0.94	(4.43)	(1.60)	1.83	(3.27)	5.88	(9.15)	3.40	(6.67)
2040	42.4	(218.5)	(75.0)	86.5	(164.7)	47,259,984	0.90	(4.62)	(1.59)	1.83	(3.49)	6.47	(9.96)	3.40	(6.89)
2041	40.5	(228.1)	(75.0)	87.1	(175.5)	47,721,196	0.85	(4.78)	(1.57)	1.83	(3.68)	6.83	(10.51)	3.40	(7.08)
2042	38.6	(229.5)	(75.0)	88.0	(178.0)	48,407,906	0.80	(4.74)	(1.55)	1.82	(3.68)	7.32	(10.99)	3.40	(7.08)
2043	36.3	(242.8)	(75.0)	88.8	(192.7)	48,611,413	0.75	(4.99)	(1.54)	1.83	(3.96)	7.80	(11.77)	3.40	(7.36)
2044	37.0	(244.1)	(75.0)	89.9	(192.3)	49,059,789	0.75	(4.98)	(1.53)	1.83	(3.92)	8.41	(12.33)	3.40	(7.32)
2045	33.2	(258.3)	(75.0)	90.5	(209.6)	49,806,440	0.67	(5.19)	(1.51)	1.82	(4.21)	8.79	(13.00)	3.40	(7.61)
2046	48.2	(247.2)	(75.0)	91.4	(182.6)	50,128,610	0.96	(4.93)	(1.50)	1.82	(3.64)	9.30	(12.94)	3.40	(7.04)
2047	62.1	(236.4)	(75.0)	92.3	(157.1)	50,128,610	1.24	(4.72)	(1.50)	1.84	(3.13)	9.80	(12.94)	3.40	(6.53)
2048	56.5	(261.6)	(75.0)	93.3	(186.8)	50,245,691	1.12	(5.21)	(1.49)	1.86	(3.72)	10.42	(14.14)	3.40	(7.12)
2049	54.7	(251.9)	(75.0)	94.1	(178.1)	50,128,610	1.09	(5.02)	(1.50)	1.88	(3.55)	10.83	(14.39)	3.40	(6.95)
2050	52.6	(262.6)	(75.0)	95.0	(190.1)	50,128,610	1.05	(5.24)	(1.50)	1.89	(3.79)	11.36	(15.15)	3.40	(7.19)
2051	67.8	(287.7)	(75.0)	95.9	(199.1)	50,128,610	1.35	(5.74)	(1.50)	1.91	(3.97)	11.88	(15.86)	3.40	(7.37)
2052	46.2	(247.3)	(60.0)	76.6	(184.5)	50,245,691	0.92	(4.92)	(1.19)	1.52	(3.67)	11.80	(15.48)	3.40	(7.07)
2053	24.3	(136.9)	(30.0)	38.0	(104.5)	50,128,610	0.49	(2.73)	(0.60)	0.76	(2.09)	11.43	(13.52)	3.40	(5.49)

* Includes program administration costs

** No rate impact in 2021 due to 2017 Settlement Agreement

High Fuel

	System Benefits and CEC Program Impacts (Nominal $)					Total Billed	Monthly Bill Impact ($/1,000 kWh)					Participant - Excludes Low Income		Low Income Participant	
$M	Base *	Clause	Subscription Fees	Bill Credits	Net Savings - General Body of Customers	MWh	Base	Clause	Susbscription Fees	Bill Credits	Net Savings - General Body of Customers	Participant (Assumes 5kw) Subscription Net (Fee) / Credit	Participant Monthly Bill Impact ($/1,000 kWh)	Participant (Assumes 5kw) Subscription Net (Fee) / Credit	Participant Monthly Bill Impact ($/1,000 kWh)
2021	1.0	0.0	0.0	0.0	1.0	39,857,384	**	0.00	0.00	0.00	**	0.00	**	0.00	**
2022	30.1	(8.9)	(15.0)	14.9	21.1	40,227,760	0.75	(0.22)	(0.37)	0.37	0.52	(0.49)	1.01	3.40	(2.88)
2023	83.9	(29.0)	(45.0)	44.6	54.4	40,513,294	2.07	(0.72)	(1.11)	1.10	1.34	(0.56)	1.90	3.40	(2.06)
2024	134.3	(61.6)	(75.0)	74.3	72.0	40,703,718	3.30	(1.51)	(1.84)	1.83	1.77	(0.56)	2.32	3.40	(1.63)
2025	127.5	(67.6)	(75.0)	74.8	59.7	41,205,631	3.10	(1.64)	(1.82)	1.82	1.45	(0.24)	1.69	3.40	(1.95)
2026	121.3	(76.1)	(75.0)	75.6	45.7	41,188,409	2.95	(1.85)	(1.82)	1.83	1.11	0.17	0.94	3.40	(2.29)
2027	96.8	(84.5)	(75.0)	76.3	13.5	41,513,413	2.33	(2.03)	(1.81)	1.84	0.33	0.58	(0.25)	3.40	(3.07)
2028	73.1	(88.3)	(75.0)	77.2	(13.1)	42,152,270	1.73	(2.09)	(1.78)	1.83	(0.31)	1.10	(1.41)	3.40	(3.71)
2029	75.2	(103.0)	(75.0)	77.7	(25.2)	42,481,081	1.77	(2.42)	(1.77)	1.83	(0.59)	1.42	(2.01)	3.40	(3.99)
2030	69.9	(101.4)	(75.0)	78.5	(28.1)	42,694,826	1.64	(2.37)	(1.76)	1.84	(0.66)	1.84	(2.50)	3.40	(4.06)
2031	72.0	(122.9)	(75.0)	79.2	(46.8)	43,306,946	1.66	(2.84)	(1.73)	1.83	(1.08)	2.27	(3.36)	3.40	(4.48)
2032	66.0	(120.4)	(75.0)	80.1	(49.3)	43,305,627	1.52	(2.78)	(1.73)	1.85	(1.14)	2.82	(3.95)	3.40	(4.54)
2033	67.9	(125.2)	(75.0)	80.7	(51.6)	44,128,573	1.54	(2.84)	(1.70)	1.83	(1.17)	3.15	(4.32)	3.40	(4.57)
2034	57.8	(165.6)	(75.0)	81.5	(101.3)	44,458,159	1.30	(3.72)	(1.69)	1.83	(2.28)	3.59	(5.87)	3.40	(5.68)
2035	44.5	(185.2)	(75.0)	82.3	(133.4)	44,917,813	0.99	(4.12)	(1.67)	1.83	(2.97)	4.04	(7.01)	3.40	(6.37)
2036	60.5	(180.8)	(75.0)	83.2	(112.1)	45,464,126	1.33	(3.98)	(1.65)	1.83	(2.47)	4.60	(7.07)	3.40	(5.87)
2037	71.2	(192.4)	(75.0)	83.8	(112.4)	45,732,122	1.56	(4.21)	(1.64)	1.83	(2.46)	4.95	(7.41)	3.40	(5.86)
2038	55.9	(218.0)	(75.0)	84.6	(152.5)	46,200,854	1.21	(4.72)	(1.62)	1.83	(3.30)	5.41	(8.71)	3.40	(6.70)
2039	43.5	(243.2)	(75.0)	85.5	(189.3)	46,789,936	0.93	(5.20)	(1.60)	1.83	(4.05)	5.88	(9.93)	3.40	(7.45)
2040	41.8	(259.1)	(75.0)	86.5	(205.9)	47,259,984	0.88	(5.48)	(1.59)	1.83	(4.36)	6.47	(10.83)	3.40	(7.76)
2041	39.8	(272.4)	(75.0)	87.1	(220.5)	47,721,196	0.83	(5.71)	(1.57)	1.83	(4.62)	6.83	(11.46)	3.40	(8.02)
2042	38.5	(273.8)	(75.0)	88.0	(222.4)	48,407,906	0.80	(5.66)	(1.55)	1.82	(4.59)	7.32	(11.91)	3.40	(7.99)
2043	36.5	(290.4)	(75.0)	88.8	(240.1)	48,611,413	0.75	(5.97)	(1.54)	1.83	(4.94)	7.80	(12.74)	3.40	(8.34)
2044	37.3	(287.4)	(75.0)	89.9	(235.3)	49,059,789	0.76	(5.86)	(1.53)	1.83	(4.80)	8.41	(13.21)	3.40	(8.20)
2045	33.5	(304.9)	(75.0)	90.5	(255.9)	49,806,440	0.67	(6.12)	(1.51)	1.82	(5.14)	8.79	(13.93)	3.40	(8.54)
2046	48.2	(296.4)	(75.0)	91.4	(231.9)	50,128,610	0.96	(5.91)	(1.50)	1.82	(4.63)	9.30	(13.92)	3.40	(8.03)
2047	62.1	(288.4)	(75.0)	92.3	(209.0)	50,128,610	1.24	(5.75)	(1.50)	1.84	(4.17)	9.80	(13.97)	3.40	(7.57)
2048	56.6	(319.5)	(75.0)	93.3	(244.6)	50,245,691	1.13	(6.36)	(1.49)	1.86	(4.87)	10.42	(15.29)	3.40	(8.27)
2049	55.1	(306.3)	(75.0)	94.1	(232.3)	50,128,610	1.10	(6.11)	(1.50)	1.88	(4.63)	10.83	(15.47)	3.40	(8.03)
2050	53.0	(321.2)	(75.0)	95.0	(248.3)	50,128,610	1.06	(6.41)	(1.50)	1.89	(4.95)	11.36	(16.31)	3.40	(8.35)
2051	67.9	(351.8)	(75.0)	95.9	(263.1)	50,128,610	1.35	(7.02)	(1.50)	1.91	(5.25)	11.88	(17.13)	3.40	(8.65)
2052	46.3	(300.9)	(60.0)	76.6	(238.0)	50,245,691	0.92	(5.99)	(1.19)	1.52	(4.74)	11.80	(16.54)	3.40	(8.14)
2053	24.5	(164.7)	(30.0)	38.0	(132.2)	50,128,610	0.49	(3.29)	(0.60)	0.76	(2.64)	11.43	(14.07)	3.40	(6.04)

* Includes program administration costs
** No rate impact in 2021 due to 2017 Settlement Agreement

DEF Participant with a 5 kW Subscription (Excludes Low Income)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Months	12	12	12	12	12	12	12	12	12	12
Subscription Level (kW)	5	5	5	5	5	5	5	5	5	5
Subscription Fee ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Total Generation (MWh) (10 Projects)	367,470	1,100,560	1,834,330	1,820,830	1,811,740	1,802,670	1,797,900	1,784,680	1,775,760	1,766,880
Solar Capacity (MW)	149.8	449.4	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0
Subscribers % of Total MW	0.00334%	0.00111%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%
Subscriber's Share of Generation, in kWh	12,265	12,245	12,245	12,155	12,094	12,034	12,002	11,914	11,854	11,795
Credit Escalator	1.000	1.000	1.000	1.015	1.015	1.015	1.015	1.015	1.015	1.015
Subscription Benefit Rate, With Escalation ($/kWh)	0.040370	0.040370	0.040370	0.040980	0.041590	0.042210	0.042840	0.043480	0.044130	0.044790
Bill Credit	495.15	494.32	494.34	498.11	503.01	507.95	514.17	518.01	523.13	528.29
Participant Net Benefit (Payments)										
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Bill Credit	495.15	494.32	494.34	498.11	503.01	507.95	514.17	518.01	523.13	528.29
Participant Net Benefit (Payment)	(5.85)	(6.68)	(6.66)	(2.89)	2.01	6.95	13.17	17.01	22.13	27.29
Average Monthly Net Benefit (Payment)	**(0.49)**	**(0.56)**	**(0.56)**	**(0.24)**	**0.17**	**0.58**	**1.10**	**1.42**	**1.84**	**2.27**

DEF Participant with a 5 kW Subscription (Excludes Low Income)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Months	12	12	12	12	12	12	12	12	12	12	12
Subscription Level (kW)	5	5	5	5	5	5	5	5	5	5	5
Subscription Fee ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Total Generation (MWh) (10 Projects)	1,762,210	1,749,240	1,740,510	1,731,820	1,727,250	1,714,550	1,705,970	1,697,440	1,692,970	1,680,500	1,672,090
Solar Capacity (MW)	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0
Subscribers % of Total MW	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%
Subscriber's Share of Generation, in kWh	11,764	11,677	11,619	11,561	11,530	11,446	11,388	11,331	11,302	11,218	11,162
Credit Escalator	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015
Subscription Benefit Rate, With Escalation ($/kWh)	0.045460	0.046140	0.046830	0.047530	0.048240	0.048960	0.049690	0.050440	0.051200	0.051970	0.052750
Bill Credit	534.78	538.78	544.11	549.49	556.23	560.38	565.89	571.55	578.64	583.01	588.80
Participant Net Benefit (Payments)											
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Bill Credit	534.78	538.78	544.11	549.49	556.23	560.38	565.89	571.55	578.64	583.01	588.80
Participant Net Benefit (Payment)	33.78	37.78	43.11	48.49	55.23	59.38	64.89	70.55	77.64	82.01	87.80
Average Monthly Net Benefit (Payment)	**2.82**	**3.15**	**3.59**	**4.04**	**4.60**	**4.95**	**5.41**	**5.88**	**6.47**	**6.83**	**7.32**

DEF Participant with a 5 kW Subscription (Excludes Low Income)	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Months	12	12	12	12	12	12	12	12	12	12	12
Subscription Level (kW)	5	5	5	5	5	5	5	5	5	5	5
Subscription Fee ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Total Generation (MWh) (10 Projects)	1,663,730	1,659,360	1,647,160	1,638,920	1,630,730	1,625,970	1,614,430	1,606,380	1,598,360	1,276,790	633,960
Solar Capacity (MW)	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	599.2	299.6
Subscribers % of Total MW	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00067%	0.00083%	0.00167%
Subscriber's Share of Generation, in kWh	11,106	11,077	10,996	10,941	10,886	10,854	10,777	10,723	10,670	10,654	10,580
Credit Escalator	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.000	1.000
Subscription Benefit Rate, With Escalation ($/kWh)	0.053540	0.054340	0.055160	0.055990	0.056830	0.057680	0.058550	0.059430	0.060320	0.060320	0.060320
Bill Credit	594.63	601.93	606.52	612.57	618.65	626.07	631.01	637.30	643.61	642.66	638.19
Participant Net Benefit (Payments)											
Subscription Charge	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)	(501.00)
Bill Credit	594.63	601.93	606.52	612.57	618.65	626.07	631.01	637.30	643.61	642.66	638.19
Participant Net Benefit (Payment)	93.63	100.93	105.52	111.57	117.65	125.07	130.01	136.30	142.61	141.66	137.19
Average Monthly Net Benefit (Payment)	**7.80**	**8.41**	**8.79**	**9.30**	**9.80**	**10.42**	**10.83**	**11.36**	**11.88**	**11.80**	**11.43**

DEF Participant with a 5 kW Subscription (Low Income Customers)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Subscription Rate ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Bill Credit ($/kW-Month)	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
Participant Net Benefit Per kW	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Average Annual Net Benefit (Payment) - 5kW	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80
Average Monthly Net Benefit (Payment) - 5kW	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**

DEF Participant with a 5 kW Subscription (Low Income Customers)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Subscription Rate ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Bill Credit ($/kW-Month)	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
Participant Net Benefit Per kW	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Average Annual Net Benefit (Payment) - 5kW	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80
Average Monthly Net Benefit (Payment) - 5kW	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**

DEF Participant with a 5 kW Subscription (Low Income Customers)	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Subscription Rate ($/kW-Month)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)	(8.35)
Bill Credit ($/kW-Month)	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
Participant Net Benefit Per kW	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Average Annual Net Benefit (Payment) - 5kW	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80	40.80
Average Monthly Net Benefit (Payment) - 5kW	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**	**3.40**

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF ______________

I hereby certify that on this __________ day of __________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared LON HUBER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 4, 5, 6(b), 18, 20-26, from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 4-26) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this _________ day of ______________, 2020.

____
Lon Huber

____
Notary Public
State of North Carolina

My Commission Expires:

____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 6(a), 8(b-d) and 12 - 14, from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 4-26) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Geoff Foster

____
Notary Public
State of Florida, at Large

My Commission Expires:

____

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MATTHEW STOUT, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 7, 8(a) and 17(a-e) from STAFF's SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 4-26) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Matthew Stout

____
Notary Public
State of North Carolina

My Commission Expires:

____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 9, 10, 11, 15, 16, 17(f), 19, from STAFF's SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 4-26) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Benjamin Borsch

____
Notary Public
State of Florida, at Large

My Commission Expires:

____

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DEF's Response to Staff's Second Production of Documents, No. 4.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI   EXHIBIT: 21
PARTY: Borsch
DESCRIPTION: DEF's Response to Staff's Second Production of Documents, No. 4.
[Bates Nos. 00063-00065]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: November 2, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S
SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 4)

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Public Service Commission's ("Staff") Second Request for Production of Documents to DEF (No. 4) as follows:

REQUEST FOR PRODUCTION OF DOCUMENTS

4. Please refer to the Rebuttal Testimony of Duke Energy Florida (DEF or Company) witness Benjamin Borsch, page 8, lines 6-8, where Borsch states, "Given that the prices of natural gas and coal are currently at historically low levels, it is reasonable that the spread of high and low prices would be asymmetric with a greater 'upside' risk in the price." Please provide DEF's most recent mid, high, and low fuel price forecasts that will be used on a going-forward basis for Company/business planning purposes, and its preparation date, if different from DEF's mid, high, and low fuel price forecasts contained in witness Borsch's EXH BMHB-2 to support DEF's petition in this proceeding.

Response:
Please see the responsive attachment bearing Bates Number 20FL-CEC-002075.

Fuel Forecasts

Fuel Mid Price Forecast (2020 Spring Forecast)			
Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil
	$/MMBTU		
2020	2.02	1.86	8.61
2021	2.60	1.96	9.19
2022	2.46	2.04	9.45
2023	2.43	2.18	10.39
2024	2.43	2.29	12.28
2025	2.53	2.37	13.91
2026	2.74	2.44	14.55
2027	3.02	2.57	15.25
2028	3.41	2.68	15.83
2029	3.90	2.80	16.53
2030	4.31	2.74	17.13
2031	4.46	2.83	17.50
2032	4.69	2.91	17.89
2033	4.81	2.98	18.42
2034	5.05	3.07	18.95
2035	5.32	3.06	19.47
2036	5.53	3.11	20.00
2037	5.89	3.21	20.55
2038	6.15	3.31	21.10
2039	6.56	3.41	21.51
2040	6.65	3.51	21.95
2041	6.86	3.52	22.35
2042	7.14	3.63	22.78
2043	7.44	3.74	23.22
2044	7.72	3.86	23.69
2045	8.13	3.98	24.14
2046	8.28	4.04	24.58
2047	8.74	4.17	25.04
2048	9.00	4.30	25.50
2049	9.10	4.43	25.97
2050	9.28	4.57	26.44
2051	9.51	4.69	27.10
2052	9.75	4.81	27.78
2053	9.99	4.93	28.47

Fuel High Price Forecast (2020 Spring Forecast)			
Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil
	$/MMBTU		
2020	2.02	1.86	8.61
2021	2.60	1.96	9.19
2022	2.55	2.04	9.45
2023	2.86	2.18	10.39
2024	3.38	2.29	12.28
2025	3.79	2.38	13.91
2026	3.94	2.46	14.55
2027	4.15	2.60	15.25
2028	4.54	2.74	15.83
2029	5.03	2.90	16.53
2030	5.55	2.85	17.13
2031	5.90	2.94	17.50
2032	6.30	3.03	17.89
2033	6.51	3.11	18.42
2034	6.85	3.21	18.95
2035	7.27	3.20	19.47
2036	7.64	3.26	20.00
2037	8.11	3.34	20.55
2038	8.48	3.46	21.10
2039	9.11	3.55	21.51
2040	9.30	3.68	21.95
2041	9.61	3.68	22.35
2042	10.02	3.80	22.78
2043	10.42	3.91	23.22
2044	11.11	4.03	23.69
2045	11.74	4.15	24.14
2046	12.06	4.22	24.58
2047	12.84	4.35	25.04
2048	13.19	4.48	25.50
2049	13.54	4.62	25.97
2050	14.00	4.78	26.44
2051	14.35	4.90	27.10
2052	14.70	5.02	27.78
2053	15.07	5.14	28.47

Fuel Low Price Forecast (2020 Spring Forecast)			
Year	Natural Gas Base Cost Regular Supply Z3	CRN Coal	Distillate Oil
	$/MMBTU		
2020	2.02	1.86	8.61
2021	2.60	1.96	9.19
2022	2.46	2.04	9.45
2023	2.43	2.18	10.39
2024	2.43	2.29	12.28
2025	2.48	2.36	13.91
2026	2.58	2.44	14.55
2027	2.72	2.56	15.25
2028	2.92	2.67	15.83
2029	3.17	2.80	16.53
2030	3.44	2.73	17.13
2031	3.61	2.82	17.50
2032	3.82	2.88	17.89
2033	3.87	2.95	18.42
2034	4.02	3.03	18.95
2035	4.23	3.01	19.47
2036	4.44	3.05	20.00
2037	4.70	3.12	20.55
2038	4.90	3.19	21.10
2039	5.22	3.26	21.51
2040	5.28	3.37	21.95
2041	5.43	3.37	22.35
2042	5.61	3.47	22.78
2043	5.76	3.57	23.22
2044	5.90	3.68	23.69
2045	6.13	3.78	24.14
2046	6.16	3.84	24.58
2047	6.39	3.96	25.04
2048	6.49	4.09	25.50
2049	6.50	4.22	25.97
2050	6.53	4.37	26.44
2051	6.69	4.48	27.10
2052	6.86	4.59	27.78
2053	7.03	4.71	28.47

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DEF's Response to Staff's Amended Third Set of Interrogatories, Nos. 27-29.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 22
PARTY: Borsch
DESCRIPTION: DEF's Response to Staff's Amended Third Set of Interrogatories, Nos. 27-29. [Bates Nos. 00066-00075]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: November 2, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S AMENDED THIRD SET OF INTERROGATORIES (NOS. 27-29)

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Public Service Commission's ("Staff") Amended Third Set of Interrogatories to DEF (Nos. 27-29) as follows:

INTERROGATORIES

27. Please refer to DEF witness Borsch's Rebuttal Testimony and DEF's response to LULAC's 2nd POD, No. 9, "CO2 Planning Forecast Price.xlsx" for the questions below:

a. Please confirm that the forecast of future $/Ton CO2 Cost shown in DEF's "CO2 Planning Forecast Price.xlsx" is the fundamental data source upon which DEF derived its projection of future CO2 emissions reduction costs, or a proxy for CO2 emission prices as discussed in witness Borsch's Rebuttal Testimony, page 9. If your response is negative, please provide a detailed explanation.

b. DEF's "CO2 Planning Forecast Price.xlsx" includes two Cases: Reference Case and "Mid-Price" Case. Please specify which of these two Cases was actually used in deriving the CO2 Cost-related Solar Project CPVRR (Savings), the amounts shown on the 2nd last row in Exhibit BMHB-3.

c. If your response to Question 27.b. is not the "Mid-Price" Case, please elaborate as to why DEF selected the Reference Case for the instant petition, given that the "Mid-Price" was used by witness Borsch in developing CO2 allowance projections in Docket No. 20180149-EI, RE: DEF's Petition for a limited proceeding to approve first solar base rate adjustment (discussed in DEF's Response to Staff's First Set of Interrogatories, No. 19).

d. If your response to Question 27.b. is not the "Mid-Price" Case, please provide a Cost Effectiveness (CPVRR) sensitivity analysis by adding a row to Exhibit BMHB-3, showing the CO2 Cost amounts, corresponding to each fuel price scenario, calculated by using the $/Ton CO2 Prices that are shown in the "Mid-Price" Case.

Response:

a. Confirmed.

b. The Reference Case is the case used to derive the CO2 cost impacts in this filing, including Exhibit BMHB-3.

c. The reference case is used in this filing because the reference case corresponds to the expected cost impact of meeting the CO2 reduction targets outlined in DEF's 2019 climate goals projection. DEF's 2019 goals projection is consistent with the targets being set by many utilities as well as various states and municipal entities including several in DEF's service area. The "Mid-Price" case corresponds to the expected cost impact of meeting the CO2 reduction targets outlined in DEF's 2017 climate goal projection. This case was DEF's current case at the time of the Filing in Docket No. 20180149-EI. DEF has retained this case as a "Mid-Price" case for use in scenario analysis. In this docket, DEF did not use the "Mid-Price" case because we believed that the presentation of the Reference case showing the impact before and after the carbon costs provided sufficient bracketing of the impact for evaluation of the filing.

d. As part of the initial analysis we ran only the Mid Fuel Case with the "Mid-Price" Case CO2 cost assumption which resulted in a CO2 Cost savings of $258M.

Since we had not run the Low Fuel Case nor the High Fuel Case with the Mid-Price CO2 cost, we calculated the CO2 Cost Savings by multiplying the CO2 Tons from the Reference CO2 Case for the Low Fuel and High Fuel cases by the $/Ton CO2 Prices from the "Mid-Price" Case. Although this is an approximation, the difference is not significant.

We compared the CO2 costs savings calculated for the Mid Fuel Case using this methodology, $254M, and the savings where the CO2 Costs from the "Mid-Price" Case affected the dispatch, $258M. The $4M difference is not significant enough to affect the decision.

Although having lower Mid-Price CO2 costs would affect the number of CO2 tons released, both the CEC case and the no CEC case would be affected the same way, so the CO2 Tons differentials would not be significantly different from the ones in the Reference CO2 runs.

Cost Effectiveness (CPVRR) Analysis Results

CPVRR Through Year 2053 2020$M	Clean Energy Connection Solar - No CEC Solar			
	Low Fuel Prices - Reference CO2 Case	Mid Fuel Prices - Reference CO2 Case	Mid Fuel Prices - Mid CO2 Price Case	High Fuel Prices - Reference CO2 Case
2022 Clean Energy Connection Units	259	259	259	259
2023 Clean Energy Connection Units	454	454	454	454
2024 Clean Energy Connection Units	427	427	427	427
Conventional Generation	(353)	(353)	(353)	(353)
Fuel Cost	(702)	(827)	(828)	(1,113)
Variable Costs	(67)	(65)	(63)	(64)
Environmental Costs without Carbon	(0)	(1)	(2)	(3)
Program Administrative Costs	7	7	7	7
Total Solar Savings before CO2 Costs	**25**	**(99)**	**(99)**	**(385)**
CO2 Cost - Reference Case	(429)	(434)	(258)	(446)
Solar Project CPVRR (Savings)	**(404)**	**(533)**	**(356)**	**(831)**
Total Solar Savings before CO2 Costs	**25**	**(99)**		**(385)**
CO2 Cost - Mid-Price Case	(249)	(254)		(263)
Solar Project CPVRR (Savings)	**(224)**	**(352)**		**(649)**

28. Please refer to witness Borsch's Rebuttal Testimony and Table 1 Comparison of CO_2 Price Projections below for the following questions:

a. Witness Borsch's Rebuttal Testimony, page 9, lines 9 - 10, reads "DEF recognizes that there is today no specific regulatory policy which restricts carbon dioxide emissions or places a specific cost on them." Please provide DEF's rationale for assuming the commencement of carbon emission regulation, evidenced and included by DEF first to incur CO_2 emission-related costs in 2025, as indicated in Table 1 below.

b. Please identify the three major independent/explanatory variables, or controlling factors, DEF used/considered to develop its CO_2 Price Projections for the Reference Case and the "Mid-Price" Case, respectively.

c. Please explain in detail how DEF's Reference Case and "Mid-Price" Case CO_2 Price Projections were derived, respectively.

d. When was the Reference Case CO_2 Price Projections approved by DEF's management?

e. Has DEF relied upon the Reference Case CO_2 Price Projections in any Commission dockets? If the response is affirmative, please identify the docket number and the document/page number(s) where the Reference Case was discussed.

f. Referring to Table 1, please explain why DEF's projected $/Ton CO_2 prices (Reference Case) are significantly higher than the $/Ton CO_2 prices projected by ICF for the entire forecast period.

Table 1: Comparisons of CO2 Price Projections

DEF			DEF				ICF	ICF	ICF
Reference Case[1]			Mid-Price Case[2]				Mid CO_2[3]	High CO_2[4]	Low CO_2[5]
Year	$/Ton CO2		Year	$/Ton CO2		Year	Nominal ($/ton)	Nominal ($/ton)	Nominal ($/ton)
1/1/2020 0:00			1/1/2020 0:00			2020	0.00	0	0
1/1/2021 0:00			1/1/2021 0:00			2021	0.00	0	0
1/1/2022 0:00			1/1/2022 0:00			2022	0.00	0	0
1/1/2023 0:00			1/1/2023 0:00			2023	0.00	0	0
1/1/2024 0:00			1/1/2024 0:00			2024	0.00	0	0
1/1/2025 0:00	5		1/1/2025 0:00	5		2025	0.00	0	0
1/1/2026 0:00	9		1/1/2026 0:00	8		2026	0.52	0	0
1/1/2027 0:00	13		1/1/2027 0:00	11		2027	0.84	0	0
1/1/2028 0:00	17		1/1/2028 0:00	14		2028	1.76	14.29	0
1/1/2029 0:00	21		1/1/2029 0:00	17		2029	2.19	15.26	0
1/1/2030 0:00	25		1/1/2030 0:00	20		2030	3.33	16.30	0
1/1/2031 0:00	29		1/1/2031 0:00	23		2031	4.25	17.40	0
1/1/2032 0:00	33		1/1/2032 0:00	26		2032	5.28	18.59	0
1/1/2033 0:00	37		1/1/2033 0:00	29		2033	6.44	19.85	0
1/1/2034 0:00	41		1/1/2034 0:00	32		2034	7.72	21.20	0
1/1/2035 0:00	45		1/1/2035 0:00	35		2035	9.15	22.64	0
1/1/2036 0:00	54		1/1/2036 0:00	38		2036	10.14	24.49	0
1/1/2037 0:00	63		1/1/2037 0:00	41		2037	11.24	26.49	0
1/1/2038 0:00	72		1/1/2038 0:00	44		2038	12.44	28.66	0
1/1/2039 0:00	81		1/1/2039 0:00	47		2039	13.77	31.00	0
1/1/2040 0:00	90		1/1/2040 0:00	50		2040	15.23	33.54	0
1/1/2041 0:00	99		1/1/2041 0:00	53		2041	16.98	37.91	0
1/1/2042 0:00	108		1/1/2042 0:00	56		2042	18.93	42.86	0
1/1/2043 0:00	117		1/1/2043 0:00	59		2043	21.13	48.45	0
1/1/2044 0:00	126		1/1/2044 0:00	62		2044	23.59	54.77	0
1/1/2045 0:00	135		1/1/2045 0:00	65		2045	26.36	61.92	0
1/1/2046 0:00	144		1/1/2046 0:00	68		2046	29.47	70.00	0
1/1/2047 0:00	153		1/1/2047 0:00	71		2047	32.97	79.13	0
1/1/2048 0:00	162		1/1/2048 0:00	74		2048	36.90	89.45	0
1/1/2049 0:00	171		1/1/2049 0:00	77		2049	41.33	101.12	0
1/1/2050 0:00	180		1/1/2050 0:00	80		2050	46.31	114.32	0

Note:

(1) Data source: DEF's Response to LULAC's 2nd POD, No. 9, DEF's "CO2 Planning Forecast Price.xlsx."

(2) Data Source: DEF's Responses to LULAC's 2nd POD, No. 9, and DEF's Response to Staff's First Set of Interrogatories, No. 19, in Docket No. 2018149-EI, Re: DEF's Petition for a limited proceeding to approve first solar base rate adjustment.

(3) Data Source: FPL's Response to Staff's First Data Request, No. 33, in Docket No. 20190061-EI, RE: Petition for approval of FPL SolarTogether program and tariff, by Florida Power & Light Company.

Response:

a. Duke Energy sees the challenge of addressing climate change as real and one in which the utility industry will be required to participate, not only in response to our customers and stakeholders, but as a part of a national regulatory strategy. Specifically, Duke Energy has assumed a compliance price which may represent any number of different compliance programs beginning in 2025. 2025 was selected because Duke considers it to be the first year in which such a regime could realistically begin given the need for legislative and regulatory action plus the typical three-year compliance phase.

b. In each case, the key variable is the degree of CO2 reduction relative to the 2005 baseline. The other important variables are those common to all resource planning analyses, including load forecast, fuel prices, costs of new technologies.

c. The Duke Energy CO_2 price was developed to incentivize less carbon intensive resources on the path to net zero carbon by 2050. Based on the earliest expected time to propose, pass and implement legislation or regulation the CO_2 price is set to begin in 2025. The ultimate CO_2 price will be dependent many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

The 2018 CO_2 price started at 5 $/ton and escalated at a rate of 3$/ton per year, which incentivized CO_2 reductions of 60 to 70% by 2050 from a 2005 baseline. However, the price was not high enough to incentivize zero emitting load following resources (ZELFR) such as nuclear, hydrogen fueled generation or carbon capture and sequestration in lieu of natural gas generation prior to 2050.

In September 2019 Duke Energy announced a CO_2 reduction goal of at least 50% by 2030 and to be net zero carbon by 2050. In addition to accelerated coal retirements, additional renewables and storage there is a need for ZELFR technologies in 2035 to 2050 timeframe to facilitate the replacement of remaining coal generation and existing natural gas combined cycle generation as they meet their projected retirement date. A CO_2 price starting at 5 $/ton increasing at a rate of 5 $/ton per year incentivized new ZELFR technology in the 2040 to 2050 timeframe where increasing at a rate of 7 $/ton accelerated the selection of ZELFRs in the 2035 to 2040 timeframe. Both the 5 and 7 $/ton year incentivizes and battery storage to meet a portion of new peaking need by 2030, additional renewables, accelerated coal retirements and limits dispatch of carbon emitting generation.

There have been multiple federal legislative proposals that Duke has been tracking including:

- Climate Leadership Council - 40$/ton escalating at 5% per year
- Clean Futures Act (CES) - incentivized similar reductions to - $5/ton escalating at $7/ton per year
- Energy Innovation and Carbon Dividend Act (H.R. 763) - 15 $/ton escalating at 10 $/ton per year
- American Opportunity Carbon Free Act of 2019 (S. 1128) - 52 $/ton escalating at 8.5% per year

The Climate Leadership Council and Clean Futures Act drives a similar pace of carbon reduction as the 5 $/ton and 7 $/ton per year carbon price trajectories. The higher CO_2 prices associated with H.R. 763 and S. 1128 would drive retirement of coal and gas generation at a faster pace which would accelerate the need for ZELFRs prior to 2035. However, the pace of CO_2 reduction would be limited by the amount of renewables and storage that could be interconnect in a given year, technological development of storage and ZELFRs technologies and the impact on customer rates.

In support of Duke Energy's CO_2 reduction goal, the Reference 2020 CO_2 price is 5 $/ton starting in 2025 escalating at a rate of 5 $/ton per year. This CO_2 price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net zero by 2050. When comparing alternative plans the inclusion of the CO_2 price in the overall project economics would be reflective of a carbon tax and if excluded would be reflective a mass CO2 cap or cap and trade with allowance allocations.

In DEF analyses a reference price starting at a lower escalation rate of 4 $/ton through 2034 and escalating at higher rate of 9 $/ton post 2034 was selected. This trajectory incentivizes the same pace of CO2 reduction as the 5 $/ton escalation rate but would have lower near-term customer economics impacts. DEF is currently using this price trajectory for regulatory purposes.

d. The Reference Case CO2 Price Projections were approved by DEF's management in the Fall of 2019.

e. Yes. DEF relied on the Reference Case CO2 Price Projections in the preparation of the 2020 Ten-Year Site Plan and also in the preparation and filing for Docket No. 2020153-EI, RE: DEF's Petition for a limited proceeding to approve the third solar base rate adjustment.

f. DEF does not have enough information regarding the development of the ICF projection to explain the differences.

29. Please refer to the Rebuttal Testimony of Duke Energy Florida (DEF or Company) witness Benjamin Borsch, page 7, lines 14-15, where Borsch states, "DEF's base case fuel price forecast was developed using short-term and long term spot market price projections from industry-recognized sources." Please provide a list of any formal proceedings, other than the Company's 2020 Ten Year Site Plan review, in which DEF has filed and/or used the same fuel price forecast presented in this docket.

Response:

DEF used the referenced fuel price projection in the preparation and filing of Docket No. 20200153-EI, regarding DEF's Petition for a limited proceeding to approve third solar base rate adjustment.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 27-29, from STAFF'S AMENDED THIRD SET OF INTERROGATORIES (NOS. 27-29) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Benjamin Borsch

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

23

DEF’s Corrected Response to LULAC’s First Set of Interrogatories,

No. 1, 8.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 23
PARTY: Huber (1) Foster (8)
DESCRIPTION: DEF’s Corrected Response to LULAC’s First Set of Interrogatories,No. 1, 8. [Bates Nos. 00076-00082]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Served: October 14, 2020

DUKE ENERGY FLORIDA, LLC'S CORRECTED RESPONSE TO LEAGUE OF UNITED LATIN AMERICAN CITIZENS' FIRST SET OF INTERROGATORIES (NOS. 1-8)

Duke Energy Florida, LLC ("DEF"), responds to League of United Latin American Citizens' ("LULAC") First Set of Interrogatories to DEF (Nos. 1-8) as follows:

INTERROGATORIES

1. Please identify the Industrial, Commercial, and Education customers that have preregistered to participate in the Clean Energy Connection program. For each customer so identified, please provide a) their subscription size; b) the percent the subscription size represents of their electricity usage; and c) the lifetime net billing credits the customer should expect to receive from their subscription (equivalent of the number represented on Exhibit No. TGF-1, row "Participant Net Distribution (Payment)," column "Nominal Total").

Response:
Please see chart below. For customer privacy, their names have not been included.

Customer #	Sector	Subscription Size (kW)	% of usage	Lifetime Credits ($)
1	Local Government	522	40%	216,634
2	Local Government	1,226	39%	508,800
3	Local Government	5,279	40%	2,190,826
4	Local Government	11,409	40%	4,734,824
5	Local Government	321	40%	133,218
6	Local Government	343	40%	142,348
7	Local Government	2,960	41%	1,228,423
8	Local Government	4,080	40%	1,693,232
9	Local Government	215	40%	89,227
10	Local Government	2,610	42%	1,083,170
11	Local Government	27,542	40%	11,430,145
12	Local Government	1,748	40%	725,434
13	Local Government	11,387	40%	4,725,694
14	Local Government	56	1%	23,240
15	Local Government	128	40%	53,121
16	Local Government	2,649	41%	1,099,356
17	Local Government	2,426	41%	1,006,809

18	School	133,994	71%	55,608,554
19	Commercial	84,980	71%	35,267,362
20	Commercial	6,363	71%	2,640,695
21	Industrial	105,785	63%	43,901,599
22	Commercial	20,592	71%	8,545,840
23	Commercial	17,631	71%	7,317,002
24	Industrial	58	6%	24,070
25	School	6,753	71%	2,802,548
26	School	80,943	69%	33,591,975
27	Commercial	565	71%	234,479
28	School	5,020	68%	2,083,339
29	Healthcare	22,037	71%	9,145,527
30	Commercial	2,131	71%	884,382

8. If there were no subscription fees or bill credits (as in, Clean Energy Connection was not a subscription based program), but the program otherwise still went forward as presented by DEF, please identify, by year, how the row “Total Gen. Body of Customers Net RevReqs (fav) unfav” on Exhibit TGF-1 would differ from the current row on Exhibit TGF-1.

Response:

DEF has not performed this analysis. As provided for in the CEC stipulation, DEF acknowledges that the CEC Program will allow it to accelerate the amount of solar generation on its system.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF ______________

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared LON HUBER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 1-4, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of ______________, 2020.

____
Lon Huber

____
Notary Public
State of North Carolina, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 6-8, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Geoff Foster

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 5, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Benjamin Borsch

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

24

DEF's Corrected Response to LULAC's First Production of Documents, No. 1.

Confidential DN. 11723-2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 24
PARTY: Foster
DESCRIPTION: DEF's Corrected Response to LULAC's First Production of Documents, No. 1. Confidential DN. 11723-2020...

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Served: November 3, 2020

DUKE ENERGY FLORIDA, LLC'S CORRECTED RESPONSE TO LEAGUE OF UNITED LATIN AMERICAN CITIZENS' FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-8)

Duke Energy Florida, LLC ("DEF"), responds to League of United Latin American Citizens' ("LULAC") First Request for Production of Documents to DEF (Nos. 1-8) as follows:

REQUEST FOR PRODUCTION OF DOCUMENTS

1. Please provide any and all documents, including drafts, that DEF has prepared or used relating to Exhibit No. TGF-1. This request specifically includes, but is not limited to, any workpapers, excel documents, or source documents related to Exhibit No. TGF-1. This request specifically includes, not is not limited to, Exhibit TGF-1 in its native format with data for all years (i.e., not with the years 2033-2053 collapsed into a single column).

Response:
All documents that DEF has prepared or used relating to Exhibit No. TGF-1 are attached to this response. DEF does not have Exhibit TGF-1 in a format with years 2033-2053 not collapsed. However, the data used for Exhibit TGF-1, including the individual years from 2033-2053 can be found in the file provided in this response, titled "CEC 749MW Model Case – Settlement (Filing)". Please see documents bearing Bates number 20FL-CEC-000001 - 20FL-CEC-000046. Please note that some of the information on these pages is confidential

2. Please provide any and all documents, including drafts, that DEF has prepared or used relating to Exhibit BMHB-2. This request specifically includes, but is not limited to, any workpapers, excel documents, or source documents related to Exhibit No. BMHB-2.

Response:
Please see documents bearing Bates number 20FL-CEC000047 through 20FL-CEC000257. Please note that some of the information on these pages is confidential

3. Please provide any and all documents, including drafts, that DEF has prepared or used relating to Exhibit BMHB-3. This request specifically includes, but is not limited to, any workpapers, excel documents, or source documents related to Exhibit No. BMHB-3.

Slipsheet: Documents bearing bates numbers

20FL-CEC-000001 - 20FL-CEC-000039

are confidential in their entirety.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SoBra 700MWs Case																	
Fuel Costs	850	859	884	902	913	972	1,056	1,187	1,360	1,477	1,569	1,646	1,750	1,766	1,818	1,881	1,939
Variable Costs	86	91	99	107	117	129	151	171	195	208	232	253	266	284	290	304	322
Environmental Costs	6	6	6	6	6	6	6	7	7	8	8	8	7	6	3	2	2
CO2 Costs	-	-	-	-	-	102	184	267	358	445	534	605	690	767	794	850	1,035
Total Costs	942	957	989	1,014	1,036	1,210	1,397	1,632	1,920	2,139	2,343	2,512	2,713	2,824	2,906	3,036	3,298
Clean Energy Connection 750MWs Case	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Fuel Costs	850	859	875	878	865	924	1,004	1,130	1,303	1,410	1,507	1,572	1,678	1,693	1,739	1,803	1,860
Variable Costs	86	91	98	103	112	125	146	166	189	203	226	246	259	279	283	297	317
Environmental Costs	6	6	6	6	5	6	6	6	7	8	8	8	7	6	3	2	2
CO2 Costs	-	-	-	-	-	98	176	256	344	426	516	583	665	739	761	814	993
Total Costs	942	957	979	986	982	1,152	1,332	1,558	1,842	2,046	2,256	2,409	2,610	2,716	2,786	2,916	3,172
Clean Energy Connection 750MWs Case - SoBra 700MWs Case	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Fuel Costs	-	-	(8)	(24)	(48)	(49)	(52)	(57)	(57)	(67)	(62)	(73)	(72)	(74)	(79)	(78)	(79)
Variable Costs	-	-	(1.397)	(3.844)	(5.346)	(4.435)	(4.627)	(5.101)	(6.083)	(5.248)	(5.762)	(6.693)	(6.376)	(5.759)	(6.858)	(7.070)	(5.103)
Environmental Costs	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	(0)	(0)	(0)
CO2 Costs	-	-	-	-	-	(5)	(8)	(11)	(14)	(20)	(18)	(22)	(25)	(28)	(33)	(35)	(42)
Total Costs Reduction	-	-	(10)	(28)	(54)	(58)	(65)	(73)	(77)	(92)	(87)	(102)	(103)	(107)	(119)	(120)	(126)

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
SoBra 700MWs Case																	
Fuel Costs	2,101	2,221	2,304	2,426	2,544	2,602	2,663	2,805	2,982	3,133	3,176	3,310	3,354	3,435	3,553	3,674	3,744
Variable Costs	360	382	422	430	456	464	485	499	530	546	572	592	615	634	665	679	709
Environmental Costs	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO2 Costs	1,220	1,409	1,613	1,807	2,013	2,165	2,344	2,561	2,764	2,985	3,164	3,371	3,542	3,774	3,997	4,224	4,391
Total Costs	3,683	4,014	4,341	4,665	5,015	5,233	5,494	5,867	6,278	6,666	6,914	7,275	7,513	7,844	8,218	8,579	8,846
Clean Energy Connection 750MWs Case	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**
Fuel Costs	2,013	2,131	2,209	2,327	2,442	2,502	2,557	2,700	2,871	3,021	3,065	3,188	3,239	3,316	3,425	3,565	3,688
Variable Costs	357	375	415	423	450	457	478	493	522	538	567	584	607	626	671	673	704
Environmental Costs	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO2 Costs	1,170	1,352	1,546	1,733	1,932	2,081	2,252	2,467	2,663	2,878	3,054	3,248	3,421	3,645	3,854	4,101	4,325
Total Costs	3,543	3,860	4,173	4,485	4,826	5,042	5,289	5,662	6,057	6,439	6,688	7,022	7,270	7,590	7,951	8,342	8,719
Clean Energy Connection 750MWs Case - SoBra 700MWs Case	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**
Fuel Costs	(88)	(90)	(95)	(99)	(102)	(100)	(106)	(104)	(111)	(113)	(111)	(122)	(115)	(119)	(128)	(108)	(56)
Variable Costs	(2.375)	(6.844)	(6.769)	(6.519)	(6.696)	(7.139)	(7.883)	(5.721)	(7.985)	(8.180)	(4.317)	(7.792)	(7.402)	(7.495)	5.969	(6.173)	(5.011)
Environmental Costs	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
CO2 Costs	(50)	(57)	(67)	(74)	(81)	(84)	(92)	(94)	(101)	(106)	(109)	(123)	(121)	(128)	(144)	(123)	(65)
Total Costs Reduction	(141)	(154)	(169)	(180)	(189)	(191)	(205)	(204)	(221)	(227)	(225)	(254)	(244)	(254)	(266)	(238)	(126)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CEC Generation (Gwh)	-	-	367	1,101	1,834	1,821	1,812	1,803	1,798	1,785	1,776	1,767	1,762	1,749	1,741	1,732	1,727
Degradation Factor 0.5%						-0.7%	-0.5%	-0.5%	-0.3%	-0.7%	-0.5%	-0.5%	-0.3%	-0.7%	-0.5%	-0.5%	-0.3%
									Leap Year				Leap Year				Leap Year
$ (353)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SoBra 700MWs Case $M																	
Conventional Generation (Gen & Transm Cap / FOM / GR)	-	-	-	-	-	-	-	22	48	54	64	71	80	86	367	834	817
Clean Energy Connection 750MWs Case $M																	
Conventional Generation (Gen & Transm Cap / FOM / GR	-	-	-	-	-	-	-	11	18	29	36	47	54	64	312	750	762
Conventional Generation (Gen & Transm Cap / FOM / GR	-	-	-	-	-	-	-	(10.974)	(29.539)	(25.262)	(28.005)	(23.710)	(26.624)	(22.289)	(55.056)	(84.028)	(54.928)

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
CEC Generation (Gwh)	1,715	1,706	1,697	1,693	1,681	1,672	1,664	1,659	1,647	1,639	1,631	1,626	1,614	1,606	1,598	1,277	634
Degradation Factor 0.5%	-0.7%	-0.5%	-0.5%	-0.3%	-0.7%	-0.5%	-0.5%	-0.3%	-0.7%	-0.5%	-0.5%	-0.3%	-0.7%	-0.5%			
				Leap Year				Leap Year				Leap Year					
$ (353)	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
SoBra 700MWs Case $M																	
Conventional Generation (Gen & Transm Cap / FOM / GR)	801	872	917	929	933	1,132	1,566	1,601	1,650	1,642	1,610	1,579	1,548	1,518	1,488	1,458	1,429
Clean Energy Connection 750MWs Case $M																	
Conventional Generation (Gen & Transm Cap / FOM / GR	767	809	834	847	852	1,052	1,487	1,523	1,572	1,599	1,592	1,561	1,530	1,500	1,470	1,440	1,411
Conventional Generation (Gen & Transm Cap / FOM / GR	(34.356)	(63.093)	(82.986)	(81.897)	(80.825)	(79.808)	(78.935)	(78.163)	(77.401)	(42.637)	(18.167)	(18.200)	(18.216)	(18.263)	(18.284)	(18.182)	(18.074)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gen Increase		-	-	367	1,101	1,834	1,821	1,812	1,803	1,798	1,785	1,776	1,767	1,762	1,749	1,741	1,732	1,727
Fuel Costs		-	-	(8)	(24)	(48)	(49)	(52)	(57)	(57)	(67)	(62)	(73)	(72)	(74)	(79)	(78)	(79)
Variable Costs		-	-	(1)	(4)	(5)	(4)	(5)	(5)	(6)	(5)	(6)	(7)	(6)	(6)	(7)	(7)	(5)
Environmental Costs		-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	(0)	(0)	(0)
CO2 Costs		-	-	-	-	-	(5)	(8)	(11)	(14)	(20)	(18)	(22)	(25)	(28)	(33)	(35)	(42)
Total		-	-	(10)	(28)	(54)	(58)	(65)	(73)	(77)	(92)	(87)	(102)	(103)	(107)	(119)	(120)	(126)
	($826,876.60)	-	-	(8,319.39)	(24,187.05)	(48,387.81)	(48,685.04)	(51,746.21)	(56,972.23)	(57,119.19)	(67,116.01)	(62,445.69)	(73,264.92)	(71,576.78)	(73,565.15)	(79,317.35)	(77,598.36)	(78,910.52)
	$66,994.12	-	-	(22.64)	(21.98)	(26.38)	(26.74)	(28.56)	(31.60)	(31.77)	(37.61)	(35.17)	(41.47)	(40.62)	(42.06)	(45.57)	(44.81)	(45.69)
	$819,489.97	-	-	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99
		-	-	367	1,101	1,834	1,821	1,812	1,803	1,798	1,785	1,776	1,767	1,762	1,749	1,741	1,732	1,727
		6.70%																

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	
Gen Increase	1,715	1,706	1,697	1,693	1,681	1,672	1,664	1,659	1,647	1,639	1,631	1,626	1,614	1,606	1,598	1,277	634	
Fuel Costs	(88)	(90)	(95)	(99)	(102)	(100)	(106)	(104)	(111)	(113)	(111)	(122)	(115)	(119)	(128)	(108)	(56)	
Variable Costs	(2)	(7)	(7)	(7)	(7)	(7)	(8)	(6)	(8)	(8)	(4)	(8)	(7)	(7)	6	(6)	(5)	
Environmental Costs	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
CO2 Costs	(50)	(57)	(67)	(74)	(81)	(84)	(92)	(94)	(101)	(106)	(109)	(123)	(121)	(128)	(144)	(123)	(65)	
Total	(141)	(154)	(169)	(180)	(189)	(191)	(205)	(204)	(221)	(227)	(225)	(254)	(244)	(254)	(266)	(238)	(126)	
($826,876.60)	(87,947.21)	(89,928.88)	(95,076.90)	(99,306.57)	#########	#########	#########	#########	#########	#########	#########	#########	#########	#########	#########	#########	(56,079.07)	
$66,994.12	(51.29)	(52.71)	(56.01)	(58.66)	(60.69)	(60.07)	(63.44)	(62.88)	(67.64)	(68.76)	(68.18)	(75.28)	(71.45)	(73.85)	(80.16)	(84.83)	(88.46)	
$819,489.97	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	$66.99	
	1,715	1,706	1,697	1,693	1,681	1,672	1,664	1,659	1,647	1,639	1,631	1,626	1,614	1,606	1,598	1,277	634	-

NPV SUMMARY	
Gen NPV (MWh)	19,439,752
Fuel Costs NPV	($826,876,603)
Variable Costs NPV	($64,552,537)
Environmental Costs NPV	($1,347,786)
CO2 Costs NPV	($434,118,598)
Total NPV	($1,326,895,523)
LCOE	**$/MWh**
Fuel Only	42.54
Variable O&M Only	3.32
Environmental Only	0.07
CO2 Only	22.33
Total Benefits LCOE	***68.26***

CPVRR Through Year 2053 2020$M - Resource Plan through 2046 and extension through 2053 $M	With Carbon Costs_Mid Fuel		
	SoBra 700MWs	Clean Energy Connection 750MWs	Clean Energy Connection 750MWs - SoBra 700MWs
2022 Clean Energy Connection	-	259	259
2023 Clean Energy Connection	-	454	454
2024 Clean Energy Connection	-	427	427
Conventional Generation (Capital / FOM / Gas Reserv.)	10,782	10,429	(353)
Fuel Cost	22,837	22,010	(827)
Variable Costs	3,573	3,509	(65)
Environmental Costs without Carbon	72	71	(1)
Adm. Costs	-	7	7
Total Solar Savings before CO2 Costs	**37,265**	**37,166**	**(99)**
CO2 Cost	11,831	11,396	(434)
CPVRR Through Year 2053 2020 $M	**49,095**	**48,562**	**(533)**

		Fuel	VOM	Enviro	Carbon	Fixed Costs	Production GWH
		Benefits - ($MMs Nominal)					
-1	2020	-	-	-	-	-	-
0	2021	-	-	-	-	-	-
1	2022	(8.32)	(1.40)	(0.07)	-	-	367.47
2	2023	(24.19)	(3.84)	(0.11)	-	-	1,100.56
3	2024	(48.39)	(5.35)	(0.29)	-	-	1,834.33
4	2025	(48.69)	(4.43)	(0.34)	(4.66)	-	1,820.83
5	2026	(51.75)	(4.63)	(0.28)	(8.10)	-	1,811.74
6	2027	(56.97)	(5.10)	(0.17)	(11.21)	(10.97)	1,802.67
7	2028	(57.12)	(6.08)	(0.07)	(14.19)	(29.54)	1,797.90
8	2029	(67.12)	(5.25)	(0.38)	(19.65)	(25.26)	1,784.68
9	2030	(62.45)	(5.76)	0.08	(18.49)	(28.01)	1,775.76
10	2031	(73.26)	(6.69)	0.03	(22.39)	(23.71)	1,766.88
11	2032	(71.58)	(6.38)	0.11	(24.71)	(26.62)	1,762.21
12	2033	(73.57)	(5.76)	0.04	(28.01)	(22.29)	1,749.24
13	2034	(79.32)	(6.86)	(0.04)	(33.01)	(55.06)	1,740.51
14	2035	(77.60)	(7.07)	(0.06)	(35.12)	(84.03)	1,731.82
15	2036	(78.91)	(5.10)	(0.07)	(41.60)	(54.93)	1,727.25
16	2037	(87.95)	(2.37)	(0.07)	(50.33)	(34.36)	1,714.55
17	2038	(89.93)	(6.84)	(0.07)	(56.91)	(63.09)	1,705.97
18	2039	(95.08)	(6.77)	(0.06)	(66.88)	(82.99)	1,697.44
19	2040	(99.31)	(6.52)	(0.06)	(73.75)	(81.90)	1,692.97
20	2041	(101.99)	(6.70)	(0.06)	(80.65)	(80.82)	1,680.50
21	2042	(100.45)	(7.14)	(0.07)	(83.59)	(79.81)	1,672.09
22	2043	(105.55)	(7.88)	(0.06)	(91.79)	(78.93)	1,663.73
23	2044	(104.34)	(5.72)	(0.07)	(94.27)	(78.16)	1,659.36
24	2045	(111.42)	(7.99)	(0.07)	(101.43)	(77.40)	1,647.16
25	2046	(112.69)	(8.18)	(0.07)	(106.42)	(42.64)	1,638.92
26	2047	(111.18)	(4.32)	(0.07)	(109.47)	(18.17)	1,630.73
27	2048	(122.40)	(7.79)	(0.06)	(123.43)	(18.20)	1,625.97
28	2049	(115.34)	(7.40)	(0.07)	(120.81)	(18.22)	1,614.43
29	2050	(118.63)	(7.50)	(0.07)	(128.27)	(18.26)	1,606.38
30	2051	(128.12)	5.97	(0.07)	(143.88)	(18.28)	1,598.36
31	2052	(108.31)	(6.17)	(0.05)	(123.27)	(18.18)	1,276.79
32	2053	(56.08)	(5.01)	(0.03)	(65.12)	(18.07)	633.96
33	2054	-	-	-	-	-	-
34	2055	-	-	-	-	-	-
35	2056	-	-	-	-	-	-
Total		(2,647.96)	(178.04)	(2.71)	(1,881.41)	(1,187.90)	51,333.16
NPV (2020$'s)		(826.88)	(64.55)	(1.35)	(434.12)	(353.46)	

Capital Deployment Schedule/Cash Outflow - DERIVATION FOR CEC PROGRAM

ARCHER - w/o Land											
Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12
W/O Network Upgrades					$ 377,363	$ 168,933	$ 2,929,472	$ 132,480	$ 3,135,065	$ 7,891,716	$ 1,375,481
All Capital					$ 377,363	$ 168,933	$ 2,929,472	$ 132,480	$ 3,135,065	$ 7,891,716	$ 1,375,481
Monthly	0.00%	0.00%	0.00%	0.00%	0.35%	0.16%	2.69%	0.12%	2.88%	7.26%	1.26%
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	0.35%	0.50%	3.20%	3.32%	6.20%	13.46%	14.72%
CHARLIE CREEK											
Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12
W/O Network Upgrades					$ 4,044,230	$ 408,520	$ 692,726	$ 404,624	$ 408,166	$ 2,889,392	$ 2,727,495
W/ Network Upgrades					$ 4,044,230	$ 408,520	$ 692,726	$ 404,624	$ 408,166	$ 2,889,392	$ 2,727,495
Monthly	0.00%	0.00%	0.00%	0.00%	3.57%	0.36%	0.61%	0.36%	0.36%	2.55%	2.41%
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	3.57%	3.94%	4.55%	4.91%	5.27%	7.82%	10.23%
DUETEE - w/o Land											
Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12
W/O Network Upgrades					$ 562,060	$ 2,041,185	$ 4,646,442	$ 153,297	$ 5,520,248	$ 2,920,692	$ 401,860
W/ Network Upgrades					$ 562,060	$ 2,041,185	$ 4,646,442	$ 153,297	$ 5,520,248	$ 2,920,692	$ 672,060
Monthly	0.00%	0.00%	0.00%	0.00%	0.55%	1.98%	4.51%	0.15%	5.36%	2.84%	0.65%
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	0.55%	2.53%	7.04%	7.19%	12.56%	15.39%	16.05%

ARCHER - w/o Land													
Cash Flow for AFUDC Calc	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades	$ 8,947,981	$ 5,540,977	$ 3,308,205	$ 3,447,338	$ 3,473,384	$ 3,478,593	$ 13,312,904	$ 14,424,224	$ 14,154,848	$ 9,627,714	$ 2,744,265	$ 2,744,265	101,215,208
All Capital	$ 8,947,981	$ 5,540,977	$ 3,308,205	$ 4,953,138	$ 4,979,184	$ 4,984,393	$ 14,818,704	$ 15,930,024	$ 14,154,848	$ 9,627,714	$ 2,744,265	$ 2,744,265	108,744,208
Monthly	8.23%	5.10%	3.04%	4.55%	4.58%	4.58%	13.63%	14.65%	13.02%	8.85%	2.52%	2.52%	
Cumulative Monthly	22.95%	28.05%	31.09%	35.64%	40.22%	44.81%	58.43%	73.08%	86.10%	94.95%	97.48%	100.00%	
CHARLIE CREEK													
Cash Flow for AFUDC Calc	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades	$ 5,313,078	$ 5,112,242	$ 5,278,663	$ 5,460,718	$ 11,055,557	$ 14,746,709	$ 13,992,787	$ 12,332,809	$ 2,636,340	$ 2,507,203	$ 2,452,448	$ 2,452,448	94,916,156
W/ Network Upgrades	$ 5,313,078	$ 5,112,242	$ 5,278,663	$ 9,103,442	$ 14,698,282	$ 18,389,433	$ 17,635,512	$ 15,975,534	$ 2,636,340	$ 2,507,203	$ 2,452,448	$ 2,452,448	113,129,779
Monthly	4.70%	4.52%	4.67%	8.05%	12.99%	16.26%	15.59%	14.12%	2.33%	2.22%	2.17%	2.17%	
Cumulative Monthly	14.93%	19.45%	24.11%	32.16%	45.15%	61.41%	77.00%	91.12%	93.45%	95.66%	97.83%	100.00%	
DUETEE - w/o Land													
Cash Flow for AFUDC Calc	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades	$ 8,807,540	$ 5,334,528	$ 2,899,403	$ 11,855,414	$ 11,863,220	$ 11,988,496	$ 8,114,857	$ 5,966,721	$ 5,728,338	$ 6,096,739	$ 2,682,680	$ 2,630,636	100,214,356
W/ Network Upgrades	$ 8,807,540	$ 5,334,528	$ 3,169,603	$ 12,125,614	$ 12,133,420	$ 12,393,796	$ 8,520,157	$ 6,372,021	$ 6,133,638	$ 6,096,739	$ 2,682,680	$ 2,630,636	102,916,356
Monthly	8.56%	5.18%	3.08%	11.78%	11.79%	12.04%	8.28%	6.19%	5.96%	5.92%	2.61%	2.56%	
Cumulative Monthly	24.61%	29.79%	32.87%	44.65%	56.44%	68.48%	76.76%	82.95%	88.91%	94.84%	97.44%	100.00%	

Monthly Spend as % of Total Capital (excluding Land)

	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11
Archer	0.00%	0.00%	0.00%	0.35%	0.16%	2.69%	0.12%	2.88%	7.26%	1.26%	8.23%
Charlie Creek	0.00%	0.00%	0.00%	3.57%	0.36%	0.61%	0.36%	0.36%	2.55%	2.41%	4.70%
Duette	0.00%	0.00%	0.00%	0.55%	1.98%	4.51%	0.15%	5.36%	2.84%	0.65%	8.56%
Average	0.00%	0.00%	0.00%	1.49%	0.83%	2.61%	0.21%	2.87%	4.22%	1.44%	7.16%

										COD	
	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0
Archer	5.10%	3.04%	4.55%	4.58%	4.58%	13.63%	14.65%	13.02%	8.85%	2.52%	2.52%
Charlie Creek	4.52%	4.67%	8.05%	12.99%	16.26%	15.59%	14.12%	2.33%	2.22%	2.17%	2.17%
Duette	5.18%	3.08%	11.78%	11.79%	12.04%	8.28%	6.19%	5.96%	5.92%	2.61%	2.56%
Average	4.93%	3.60%	8.13%	9.79%	10.96%	12.50%	11.65%	7.10%	5.66%	2.43%	2.42%

Cumulative Spend as % of Total Capital (excluding Land)

	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11
Archer	0.00%	0.00%	0.00%	0.35%	0.50%	3.20%	3.32%	6.20%	13.46%	14.72%	22.95%
Charlie Creek	0.00%	0.00%	0.00%	3.57%	3.94%	4.55%	4.91%	5.27%	7.82%	10.23%	14.93%
Duette	0.00%	0.00%	0.00%	0.55%	2.53%	7.04%	7.19%	12.56%	15.39%	16.05%	24.61%
Quarterly Cumulative Average	***0.00%***			***1.49%***			***5.14%***			***13.67%***	

										COD	
	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0
Archer	28.05%	31.09%	35.64%	40.22%	44.81%	58.43%	73.08%	86.10%	94.95%	97.48%	100.00%
Charlie Creek	19.45%	24.11%	32.16%	45.15%	61.41%	77.00%	91.12%	93.45%	95.66%	97.83%	100.00%
Duette	29.79%	32.87%	44.65%	56.44%	68.48%	76.76%	82.95%	88.91%	94.84%	97.44%	100.00%
Quarterly Cumulative Average		***29.36%***			***58.23%***			***89.49%***			***100.00%***

	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11
6.07% 100.4923%											
$ 93,000,000				1,385,083	774,938	2,424,514	194,818	2,668,352	3,921,226	1,341,939	6,659,690
Cumulative	-	-	-	-	1,385,083	2,160,022	4,584,536	4,779,354	7,447,705	11,368,931	12,710,870
Ave Add	-	-	-	692,542	387,469	1,212,257	97,409	1,334,176	1,960,613	670,970	3,329,845
AFUDC on Ave Add	-	-	-	695,950.98	389,376.50	1,218,224.98	97,888.29	1,340,743.77	1,970,264.65	674,272.80	3,346,237.25
AFUDC on Full Monthly		-	-	-	2,091,279	5,362,899	14,412,871	29,190,842	62,554,217	131,336,870	265,346,428
Ending including AFUDC	-	-	-	2,081,034	5,336,628	14,342,267	29,047,844	62,247,781	130,693,488	264,046,571	539,398,926

	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	
$ 93,000,000	4,587,288	3,344,280	7,558,966	9,101,849	10,193,219	11,623,321	10,838,206	6,605,121	5,268,058	2,262,403	2,246,727	
Cumulative	19,370,560	23,957,848	27,302,128	34,861,095	43,962,944	54,156,163	65,779,484	76,617,691	83,222,812	88,490,870	90,753,273	93,000,000
Ave Add	2,293,644	1,672,140	3,779,483	4,550,925	5,096,609	5,811,661	5,419,103	3,302,561	2,634,029	1,131,202	1,123,363	
AFUDC on Ave Add	2,304,935.22	1,680,371.61	3,798,088.96	4,573,328.17	5,121,699.19	5,840,270.49	5,445,780.52	3,318,818.49	2,646,995.86	1,136,770.42	1,128,893.61	
AFUDC on Full Monthly	542,054,297	###########	###########	###########	###########	###########	###########	###########	###########	###########	###########	
Ending including AFUDC	###########	###########	###########	###########	###########	###########	###########	###########	###########	###########	###########	
											###########	

Generic Project

AFUDC Entity: DE Florida (NOTE 1)

	Total Annual Rate	Total Monthly Rate	
AFUDC Rate	6.07%	0.492283%	0.49%

Include Network Upgrades: y

		AFUDC
Yes	$	2,316,758
No	$	1,967,975

Month	Monthly Charges (source: PP download)	Half Current Month Expense	Cumulative Previous Month Expense	Cumulative Prior Month AFUDC	Total AFC Base	Current Month AFUDC		Capital Deployment % of Total CapEx	Capex	
	A	*B =A*1/2*	*C=All PM Expenses*	*D=All PM AFUDC*	*E=B+C+D*	*=E*G2*		*$ 100,000,000*	*Total CapEx*	
-18.00	$ 833,267	$ 416,633	$ -	$ -	$ 416,633	$ 2,051		1.49%	$ 1,489,337	
-17.00	$ 2,607,005	$ 1,303,502	$ 833,267	$ 2,051	$ 2,136,769	$ 10,519		0.83%	$ 833,267	
-16.00	$ 209,481	$ 104,741	$ 3,440,272	$ 12,570	$ 3,557,582	$ 17,513		2.61%	$ 2,607,005	
-15.00	$ 2,869,195	$ 1,434,598	$ 3,649,753	$ 30,083	$ 5,114,434	$ 25,178		0.21%	$ 209,481	
-14.00	$ 4,216,372	$ 2,108,186	$ 6,518,948	$ 55,261	$ 8,682,395	$ 42,742		2.87%	$ 2,869,195	
-13.00	$ 1,442,946	$ 721,473	$ 10,735,320	$ 98,003	$ 11,554,796	$ 56,882		4.22%	$ 4,216,372	
-12.00	$ 7,160,957	$ 3,580,478	$ 12,178,266	$ 154,885	$ 15,913,629	$ 78,340		1.44%	$ 1,442,946	
-11.00	$ 4,932,568	$ 2,466,284	$ 19,339,223	$ 233,225	$ 22,038,732	$ 108,493		7.16%	$ 7,160,957	
-10.00	$ 3,596,000	$ 1,798,000	$ 24,271,790	$ 341,718	$ 26,411,509	$ 130,019		4.93%	$ 4,932,568	
-9.00	$ 8,127,921	$ 4,063,960	$ 27,867,790	$ 471,738	$ 32,403,488	$ 159,517		3.60%	$ 3,596,000	
-8.00	$ 9,786,935	$ 4,893,467	$ 35,995,711	$ 631,255	$ 41,520,433	$ 204,398		8.13%	$ 8,127,921	
-7.00	$ 10,960,450	$ 5,480,225	$ 45,782,646	$ 835,653	$ 52,098,524	$ 256,472		9.79%	$ 9,786,935	
-6.00	$ 12,498,195	$ 6,249,097	$ 56,743,096	$ 1,092,125	$ 64,084,319	$ 315,476		10.96%	$ 10,960,450	
-5.00	$ 11,653,985	$ 5,826,993	$ 69,241,291	$ 1,407,602	$ 76,475,886	$ 376,478		12.50%	$ 12,498,195	
-4.00	$ 7,102,281	$ 3,551,140	$ 80,895,277	$ 1,784,080	$ 86,230,497	$ 424,498		11.65%	$ 11,653,985	
-3.00	$ 5,664,578	$ 2,832,289	$ 87,997,557	$ 2,208,578	$ 93,038,425	$ 458,013		7.10%	$ 7,102,281	
-2.00	$ 2,432,692	$ 1,216,346	$ 93,662,136	$ 2,666,591	$ 97,545,072	$ 480,198		5.66%	$ 5,664,578	
-1.00	$ 2,415,835	$ 1,207,918	$ 96,094,828	$ 3,146,789	$ 100,449,534	$ 494,496		2.43%	$ 2,432,692	Last Month of AFUDC
0.00	$ -	$ -	$ 98,510,663	$ 3,641,285	$ 102,151,948	$ -		2.42%	$ 2,415,835	In-Service Month
						$ 3,641,285				
								100.00%	$ 100,000,000	
					Total AFUDC	$ 3,641,285	3.6413%			

AFUDC stops accruing at Placed In Service

From March 2020 Standard Treasury Assumptions

	After-Tax	Pre-Tax	**Notes**
ROE	10.50%		
Debt		3.15%	Marginal Cost of Debt
% Equity	53%		
% Debt	47%		
Composite Tax Rate	25.35%		2022 forward

WACC/Discount Rate	After-Tax	Pre-Tax
Equity	5.57%	7.45%
Debt	1.11%	1.48%
Total	**6.67%**	**8.94%**

Exhibit No. __(TGF-1)

Summary of CEC Program Revenue Requirements, Subscription Fees, and Bill Credits

($ millions)		CPVRR	Nominal Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033-2053
Discount Factor				0.94	0.88	0.82	0.77	0.72	0.68	0.64	0.60	0.56	0.52	0.49	0.46	
Fixed Revenue Requirements																
CEC Capital, O&M		$ 1,140.3	$ 2,728.3	$ -	$ 30.9	$ 87.1	$ 138.3	$ 131.3	$ 125.3	$ 112.4	$ 108.6	$ 105.5	$ 102.9	$ 100.5	$ 98.2	$ 1,587.4
Program Administrative Costs		$ 7.3	$ 16.8	$ 1.0	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.5	$ 0.6	$ 0.5	$ 0.5	$ 0.6	$ 0.4	$ 0.4	$ 9.6
Total DEF CEC Costs		$ 1,147.6	$ 2,745.1	$ 1.0	$ 31.5	$ 87.8	$ 139.0	$ 132.0	$ 125.8	$ 112.9	$ 109.1	$ 106.0	$ 103.5	$ 100.9	$ 98.5	$ 1,597.1
System Benefits (1)		$ (353.5)	$ (1,187.9)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.0)	$ (29.5)	$ (25.3)	$ (28.0)	$ (23.7)	$ (26.6)	$ (1,043.8)
Total Fixed Revenue Requirements (fav) unfav		**$ 794.2**	**$ 1,557.2**	**$ 1.0**	**$ 31.5**	**$ 87.8**	**$ 139.0**	**$ 132.0**	**$ 125.8**	**$ 102.0**	**$ 79.5**	**$ 80.8**	**$ 75.5**	**$ 77.2**	**$ 71.9**	**$ 553.3**
Variable Revenue Requirements																
System Net Fuel		$ (826.9)	$ (2,648.0)	$ -	$ (8.3)	$ (24.2)	$ (48.4)	$ (48.7)	$ (51.7)	$ (57.0)	$ (57.1)	$ (67.1)	$ (62.4)	$ (73.3)	$ (71.6)	$ (2,078.1)
Variable O&M		$ (64.6)	$ (178.0)	$ -	$ (1.4)	$ (3.8)	$ (5.3)	$ (4.4)	$ (4.6)	$ (5.1)	$ (6.1)	$ (5.2)	$ (5.8)	$ (6.7)	$ (6.4)	$ (123.1)
Emissions		$ (435.5)	$ (1,884.1)	$ -	$ (0.1)	$ (0.1)	$ (0.3)	$ (5.0)	$ (8.4)	$ (11.4)	$ (14.3)	$ (20.0)	$ (18.4)	$ (22.4)	$ (24.6)	$ (1,759.2)
Total Variable Revenue Requirements (fav) unfav		**$ (1,326.9)**	**$ (4,710.1)**	**$ -**	**$ (9.8)**	**$ (28.1)**	**$ (54.0)**	**$ (58.1)**	**$ (64.8)**	**$ (73.5)**	**$ (77.5)**	**$ (92.4)**	**$ (86.6)**	**$ (102.3)**	**$ (102.6)**	**$ (3,960.5)**
Net Revenue Requirements (fav) unfav		**$ (532.7)**	**$ (3,152.9)**	**$ 1.0**	**$ 21.7**	**$ 59.6**	**$ 85.0**	**$ 73.9**	**$ 61.1**	**$ 28.5**	**$ 2.1**	**$ (11.6)**	**$ (11.2)**	**$ (25.1)**	**$ (30.6)**	**$ (3,407.2)**
Participant Subscription Fees and Bill Credits	% of Total															
Subscription Fees (Revenue)		$ (833.4)	$ (2,251.5)	$ -	$ (15.0)	$ (45.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (1,516.0)
Bill Credits		$ 901.0	$ 2,542.1	$ -	$ 14.9	$ 44.6	$ 74.3	$ 74.8	$ 75.6	$ 76.3	$ 77.2	$ 77.7	$ 78.5	$ 79.2	$ 80.1	$ 1,789.0
Participant Net Distribution (Payment)	12.7%	**$ 67.6**	**$ 290.6**	**$ -**	**$ (0.1)**	**$ (0.5)**	**$ (0.8)**	**$ (0.2)**	**$ 0.5**	**$ 1.2**	**$ 2.1**	**$ 2.7**	**$ 3.4**	**$ 4.2**	**$ 5.1**	**$ 273.0**
General Body of Customers Revenue Requirement																
Fixed	% of Total															
Total Fixed Revenue Requirements		$ 794.2	$ 1,557.2	$ 1.0	$ 31.5	$ 87.8	$ 139.0	$ 132.0	$ 125.8	$ 102.0	$ 79.5	$ 80.8	$ 75.5	$ 77.2	$ 71.9	$ 553.3
Participant Subscription Fees (Revenue)	104.9%	$ (833.4)	$ (2,251.5)	$ -	$ (15.0)	$ (45.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (75.0)	$ (1,516.0)
Net Fixed Revenue Requirements (fav) unfav	-4.9%	**$ (39.2)**	**$ (694.3)**	**$ 1.0**	**$ 16.5**	**$ 42.7**	**$ 63.9**	**$ 56.9**	**$ 50.8**	**$ 26.9**	**$ 4.5**	**$ 5.7**	**$ 0.4**	**$ 2.1**	**$ (3.1)**	**$ (962.7)**
Variable	% of Total															
Total Variable Revenue Requirements (fav) unfav		$ (1,326.9)	$ (4,710.1)	$ -	$ (9.8)	$ (28.1)	$ (54.0)	$ (58.1)	$ (64.8)	$ (73.5)	$ (77.5)	$ (92.4)	$ (86.6)	$ (102.3)	$ (102.6)	$ (3,960.5)
Participant Bill Credits	67.9%	$ 901.0	$ 2,542.1	$ -	$ 14.9	$ 44.6	$ 74.3	$ 74.8	$ 75.6	$ 76.3	$ 77.2	$ 77.7	$ 78.5	$ 79.2	$ 80.1	$ 1,789.0
Net Variable Revenue Requirements (fav) unfav	32.1%	**$ (425.9)**	**$ (2,168.0)**	**$ -**	**$ 5.1**	**$ 16.4**	**$ 20.3**	**$ 16.7**	**$ 10.8**	**$ 2.8**	**$ (0.3)**	**$ (14.7)**	**$ (8.2)**	**$ (23.1)**	**$ (22.4)**	**$ (2,171.5)**
Total Gen. Body of Customers Net RevReqs (fav) unfa	87.3%	**$ (465.1)**	**$ (2,862.2)**	**$ 1.0**	**$ 21.6**	**$ 59.2**	**$ 84.2**	**$ 73.7**	**$ 61.6**	**$ 29.7**	**$ 4.2**	**$ (8.9)**	**$ (7.7)**	**$ (21.0)**	**$ (25.5)**	**$ (3,134.2)**

(1) System Impacts - Includes avoided generation capital, transmission capital, fixed O&M, and gas reservation charges

25

DEF’s Response to LULAC’s Second Set of Interrogatories,

Nos. 9, 14.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 25
PARTY: Huber
DESCRIPTION: DEF’s Response to LULAC’s Second Set of Interrogatories, Nos. 9, 14.
[Bates Nos. 00093-00099]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Filed: October 14, 2020

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO LEAGUE OF UNITED LATIN AMERICAN CITIZENS' SECOND SET OF INTERROGATORIES (NOS. 9-25)

Duke Energy Florida, LLC ("DEF"), responds to League of United Latin American Citizens' ("LULAC") Second Set of Interrogatories to DEF (Nos. 9-25) as follows:

INTERROGATORIES

9. Please list and describe the general design principles for a community solar project that DEF used in designing this proposal, and how the proposal accords with those principles.

Response:
Below are the most important design features DEF focused on in the development of the Program:

- Low income clean energy accessibility- created low income carve out with guaranteed bill savings from subscription start that would be easy to understand and enroll in
- Easy to participate- no upfront fee, no cancellation fees, low entry price point so that participants have flexibility to choose the level right for them, a website and call center to explain the program and answer questions
- Mobility- participants may take their subscription with them if they move to a new premise in the DEF service territory
- Favorable economics for participants - projected customer payback is seven years, with low income payback guaranteed from subscription start
- Renewable attribute ownership- participants own the renewable energy certificate associated with their share of the generation.

Below please find IREC's checklist principles in the design of shared renewables and how the Clean Energy Connection Program meets them.

1. **Expand Customer Access to Clean Energy**- it is undeniable that the Clean Energy Connection program meets this principle
   a. DEF conducted market research to set program features
   b. Clean Energy Connection allows all customer classes to participate and sets maximum subscription sizes
   c. Low income customer carve out of 26MW ensures cross socioeconomic participation and much thought has gone into making the program easy in which to enroll and understand, both for customers and for the community partners we intend to work with to promote the program

2. **Offer Tangible Economic Benefits for All Participating Customers**- Clean Energy Connection clearly saves customers money on their electric bills
    a. Credit values are significant enough to support a successful program
    b. Participants will receive fair compensation for their value of their blocks to the grid
    c. Fees and credits will appear on the participant's monthly bill
3. **Identify Ways to Promote Project Development Cost Savings-** The scale of the projects helps contain costs.
4. **Prioritize the Customer Experience-** Program development considered the customer's journey in every step of the program
    a. From the online application to the enrolled participant portal online, Clean Energy Connection gives customers the ability to self-serve as much as they want. DEF's Renewable Service Center will be available for customers who prefer to speak with a representative to enroll or ask questions.
    b. Large customers told us they were surprised at how easy it was to enroll and how straight forward the disclosures were.
    c. Low income customer enrollment, often a significant barrier to entry, does not involve a customer needing to go somewhere to have their income verified.
    d. Participants will be able to view monthly program fees and credits on their monthly bill.
5. **Promote Competition**- DEF, as a normal course of business, issues competitive solicitations for the engineering, procurement and engineering of its solar plants, looking at both local job creation and minority participation in its criteria.
6. **Optimize Community Solar to Benefit the Grid and the Community**- 17 local governments have signed up to participate in the program and lower their electricity bills so they can put those funds to other needs in the community. In addition, as part of this program, DEF will publish a study within two years analyzing an add-on program that would allow participants to employ storage technologies.

14. Please explain what solar or renewable energy attributes will be provided to the general body of ratepayers under the proposed program. Please detail the conditions and requirements imposed on Clean Energy Connection program subscribers relating to claims and transferability of solar or renewable energy attributes associated with program subscription.

Response:

The general body of customers will be provided with the renewable energy attributes that relate to the Greenhouse Gas, (GHG) emission offsets, reductions, or GHGs removed from the atmosphere, measured in metric tons per GHG per DEF's total aggregated resource portfolio, please see DEF's responses to LULAC's First Set of Interrogatories #5; and, for the renewable electricity generation not subscribed to by participants but further defined below as Renewable Energy Credits, (RECs). Due to attrition and bill cycles, the Program blocks may not be 100% subscribed every month, therefore every DEF customer, participant or not, may be able to make a claim that they use renewable electricity generated from the emission-free Clean Energy Connection Program portfolio since the RECs associated with any instant unsubscribed blocks of renewable electricity generation are owned by the general body of customers.

Renewable energy attributes owned by subscribers and the general body of customers for any instant unsubscribed blocks are directly tied to the renewable electricity generation which is a market recognized instrument created for every megawatt-hour, (MWh) of electricity generated and delivered to the DEF power grid from the portfolio of Clean Energy Connection resources, also known as Renewable Energy Credits, (RECs) that will be retired on a yearly basis on behalf of all customers. Large customers and local governments may request an informal attestation by the Company of their subscription level and corresponding retired RECs at no cost, and all customers will have access to DEF's website where REC creation, registration and retirements are shown in a fully transparent way. Further, if a large customer or local government would like to retire their REC in their own registry account, they may do so by - 1. providing the Company with notice; and, 2. paying Duke Energy the fee that the North American Renewable Registry, (NAR) charges to move the REC from the Clean Energy Connection Program's registry account to their registry account. The subscriber's REC will only be moved after the fee is paid; and finally, once the Company retires the Program RECs each year on behalf of all participants, the subscriber's REC cannot be moved into their individual NAR account. Currently, DEF only has 3 governmental entities that have notified of their interest to transfer RECs for sustainability tracking purposes using the NAR registry.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF ______________

I hereby certify that on this __________ day of __________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared LON HUBER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 9, 10, 12-15, 22 and 24-25, from LULAC's SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 9-25) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this _________ day of ______________, 2020.

____
Lon Huber

____
Notary Public
State of North Carolina, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this __________ day of __________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 11 and 16-21, from LULAC's SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 9-25) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this _________ day of ______________, 2020.

____
Geoff Foster

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 23, from LULAC's SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 9-25) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Benjamin Borsch

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

EXHIBIT NO. LULAC-13

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: DEF'S LATE FILED EXHIBIT NO. 1 from LULAC'S DEPOSITION of LON HUBER, BENJAMIN BORSCH, and THOMAS FOSTER, OCT. 26, 2020.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Served: November 2, 2020

DUKE ENERGY FLORIDA, LLC'S LATE-FILED EXHIBIT 1

Duke Energy Florida, LLC ("DEF"), submits its Late-Filed Exhibit Number 1 from the Deposition held on October 26, 2020 as follows:

Question

Please provide how many, of the commercial customers reflected in DEF's response to Interrogatory Number 13, could participate in the Small and Medium Business segment.

Response

Of the 178,036 commercial customers, 154,061 customers would be eligible for the small customer allocation which includes residential and small and medium businesses.

EXHIBIT NO. LULAC-15

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: DEF's *CORRECTED* RESPONSE to LULAC's FIRST SET of INTERROGATORIES (NOS.1-8)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve Clean Energy Connection Program and Tariff and Stipulation by Duke Energy Florida, LLC	Docket No. 20200176-EI Served: October 14, 2020

DUKE ENERGY FLORIDA, LLC'S CORRECTED RESPONSE TO LEAGUE OF UNITED LATIN AMERICAN CITIZENS' FIRST SET OF INTERROGATORIES (NOS. 1-8)

Duke Energy Florida, LLC ("DEF"), responds to League of United Latin American Citizens' ("LULAC") First Set of Interrogatories to DEF (Nos. 1-8) as follows:

INTERROGATORIES

1. Please identify the Industrial, Commercial, and Education customers that have preregistered to participate in the Clean Energy Connection program. For each customer so identified, please provide a) their subscription size; b) the percent the subscription size represents of their electricity usage; and c) the lifetime net billing credits the customer should expect to receive from their subscription (equivalent of the number represented on Exhibit No. TGF-1, row "Participant Net Distribution (Payment)," column "Nominal Total").

Response:
Please see chart below. For customer privacy, their names have not been included.

Customer #	Sector	Subscription Size (kW)	% of usage	Lifetime Credits ($)
1	Local Government	522	40%	216,634
2	Local Government	1,226	39%	508,800
3	Local Government	5,279	40%	2,190,826
4	Local Government	11,409	40%	4,734,824
5	Local Government	321	40%	133,218
6	Local Government	343	40%	142,348
7	Local Government	2,960	41%	1,228,423
8	Local Government	4,080	40%	1,693,232
9	Local Government	215	40%	89,227
10	Local Government	2,610	42%	1,083,170
11	Local Government	27,542	40%	11,430,145
12	Local Government	1,748	40%	725,434
13	Local Government	11,387	40%	4,725,694
14	Local Government	56	1%	23,240
15	Local Government	128	40%	53,121
16	Local Government	2,649	41%	1,099,356
17	Local Government	2,426	41%	1,006,809

18	School	133,994	71%	55,608,554
19	Commercial	84,980	71%	35,267,362
20	Commercial	6,363	71%	2,640,695
21	Industrial	105,785	63%	43,901,599
22	Commercial	20,592	71%	8,545,840
23	Commercial	17,631	71%	7,317,002
24	Industrial	58	6%	24,070
25	School	6,753	71%	2,802,548
26	School	80,943	69%	33,591,975
27	Commercial	565	71%	234,479
28	School	5,020	68%	2,083,339
29	Healthcare	22,037	71%	9,145,527
30	Commercial	2,131	71%	884,382

2. Please identify and describe any agreements DEF reached with any signatories to the "Stipulation" filed as Exhibit A to the Petition seeking approval of the Clean Energy Connection Program in this docket, which are related to this docket (including any party's participation in this docket), but that are not reflected in the "Stipulation."

Response:

Other than the Stipulation, DEF does not have any other agreements with the signatories.

3. Please identify all inducements or agreements parties were offered or agreed to in order to sign the “Stipulation” that are not reflected in the “Stipulation.”

Response:
None.

4**.** Please identify any agreement, whether written or verbal or any other format, that DEF has with any party to intervene in this docket in support of the Clean Energy Connection Program.

Response:
None.

5. Please describe all bases for DEF's assumed emissions costs assumed in this docket. Please clarify what, if any, potion of the "Emissions" revenue requirements identified on Exhibit No. TGF-1 are from currently existing laws, rules, or regulations, and please identify those existing laws, rules, and regulations.

Response:

DEF's assumed emissions costs include the following elements:

- SO2 Costs
- NOX Costs
- CO2 Costs
- Reagents (list below)
- Byproducts (Gypsum and Ash)
- Lime
- Ammonia

Reagents for Crystal River

Reagent	**Application**
50% Urea Liquor	NOx Control
Dibasic Acid	Scrubber Performance Additive
Hydrated Lime (Ca(OH2))	SO3 Control
Limestone (CaCO3)	SO2 Control
MerControl 8034PLUS	Mercury Control
Powdered Activated Carbon	Mercury Control

DEF compiles all the costs, other than the CO2, into an aggregate cost for environmental control. All these costs were related to existing regulations. The retirement of SO2 allowances are required under Title IV of the Clean Air Act Amendments of 1990 (the acid rain rule). The reagents shown are all required to meet the terms of the Crystal River 4 and 5 Title V permit. These derive from the NSPS rules for NOx and SOx emissions and the MATS rule of 2015. Ammonia is used at the combined cycle facilities for the reduction of NOx emissions. These emissions are limited in compliance with the Title V permits of the various facilities and are set to meet standard either derived from the NSPS or from ambient air quality standards. We offset the costs of the emissions control through the sale of ash and gypsum from Crystal River Units 4 and 5 to be used in building materials.

In the course of this review, DEF identified that the emissions total does include costs projected for DEF NOx allowance requirements under the Cross-State Air Pollution Protection Rule. This rule is no longer applicable to Florida emissions. DEF recognizes that this would reduce the CPVRR savings to customers by $279 thousand (vs. a total of $533 million). This value would not materially change the economic benefits as filed in DEF's petition.

DEF also calculates a proxy cost of carbon which creates an explicit price for the anticipated cost of carbon regulations. This price is equivalent to a requirement for carbon allowance purchases or a carbon tax. While the precise form of future carbon regulations is uncertain, DEF continues to forecast that regulations limiting greenhouse gas emissions, especially carbon dioxide emissions, will be a part of the mid to long-term future. These costs are broken out in DEF's exhibits (see DEF exhibit BMHB-3) so that the project value is visible both with and without the impact of the carbon price.

6. Please describe what the row “Total Gen. Body of Customers Net RevReqs (fav) unfav” on Exhibit TGF-1 represents.

Response:
This row represents a $465.1M CPVRR net benefit to the general body of customers. It also shows nominal total (~$2.8 billion) and annual net benefits to the general body of customers. This represents the net benefit to the general body of customers considering all Program revenue requirements (fixed and variable) as well as savings due to the program (fixed and variable). As can be seen in the lines above, the Program Subscription fees cover more (104.9%) than the total fixed revenue requirements of the Program. Additionally, it can be seen on the exhibit that the Total Variable Revenue Requirement impact at ~$1.3 billion favorable is significantly greater than the Participant Bill Credits at ~$901 million. In total it reflects ~87.3% of the total Program benefit going to the general body of customers.

7. Please clarify whether the "84.2" in column "2024" in row "Total Gen. Body of Customers Net RevReqs (fav) unfav" in Exhibit TGF-1 represents that in the year 2024, revenue requirements for the general body of customers is expected to increase by $84.2 million dollars as compared to if this program did not exist. If so, please describe how this amount will be collected from the general body of ratepayers.

Response:

The total nominal net revenue requirement favorable to the general body of customers over the life of the program is projected to be $2.9B. The $84.2M shown in the year 2024 reflects the projected nominal net revenue requirement applicable to the general body of customers for that particular year. As stated in the testimony of Witness Foster, DEF proposes to recover base recoverable costs through base rates. The monthly difference between the levelized subscription fees and the actual base revenue requirements, including the revenue requirements allocated to the general body of customers, will be reflected as base rate recoverable costs or benefits and included within DEF's earnings surveillance reports. At the time of DEF's next base rate case during which the solar projects are in service, DEF will include revenue related to the projected levelized subscription fees from participants and the projected base revenue requirements will be included for recovery via base rates. The bill credits will be charged to the fuel clause and netted against the fuel savings achieved by the CEC Program.

8. If there were no subscription fees or bill credits (as in, Clean Energy Connection was not a subscription based program), but the program otherwise still went forward as presented by DEF, please identify, by year, how the row “Total Gen. Body of Customers Net RevReqs (fav) unfav” on Exhibit TGF-1 would differ from the current row on Exhibit TGF-1.

Response:
DEF has not performed this analysis. As provided for in the CEC stipulation, DEF acknowledges that the CEC Program will allow it to accelerate the amount of solar generation on its system.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF ______________

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared LON HUBER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 1-4, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of ______________, 2020.

____
Lon Huber

____
Notary Public
State of North Carolina, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Numbers 6-8, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Geoff Foster

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this _________ day of _________, 2020, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared BENJAMIN BORSCH, who is personally known to me, and he acknowledged before me that he provided the answers to Interrogatory Number 5, from LULAC's FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20200176-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this ________ day of _____________, 2020.

____
Benjamin Borsch

____
Notary Public
State of Florida, at Large

My Commission Expires:
____

EXHIBIT NO. LULAC-27

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: CEC – LULAC ROG #17 POD #14 - *REDACTED* from DEF's RESPONSE to LULAC's SECOND SET of INTERROGATORIES (NOS. 9-25)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 28
PARTY: LULAC
DESCRIPTION: LULAC-27 – CEC - LULAC ROG 17 POD 14 - REDACTED from DEFs Response to LULAC 2 ROG (9-25)

No Clean Energy Connection - Mid Fuel & Mid CO_2

		Solar Revenue Requirements				Non-Solar Generation Revenue Requirements				System Revenue Requirements				
Year	Program Admin. Costs (Millions)	Generation Capital (Millions)	Transmission Interconnection (Millions)	Fixed O&M (Millions)	Capital Lease (Millions)	Generation Capital (Millions)	Fixed O&M (Millions)	Transmission Interconnection (Millions)	Incremental Gas Transport (Millions)	System Net Fuel (Millions)	Startup + VOM (Millions)	Environmental Costs without CO_2 (Millions)	CO_2 Emission (Millions)	Total RevReq (Millions)
2020	$0	[redacted]				$0	$0	$0	$0	$850	$86	$6	$0	$1,007
2021	$0					$0	$0	$0	$0	$859	$91	$6	$0	$1,059
2022	$0					$0	$0	$0	$0	$884	$99	$6	$0	$1,129
2023	$0					$0	$0	$0	$0	$902	$107	$6	$0	$1,148
2024	$0					$0	$0	$0	$0	$913	$117	$6	$0	$1,164
2025	$0					$0	$0	$0	$0	$972	$129	$6	$102	$1,331
2026	$0					$0	$0	$0	$0	$1,056	$151	$6	$184	$1,504
2027	$0					$18	$1	$3	$0	$1,187	$171	$7	$267	$1,757
2028	$0					$40	$1	$7	$0	$1,360	$195	$7	$358	$2,069
2029	$0					$46	$1	$7	$0	$1,477	$208	$8	$445	$2,292
2030	$0					$54	$2	$9	$0	$1,569	$232	$8	$534	$2,503
2031	$0					$59	$2	$10	$0	$1,646	$253	$8	$605	$2,675
2032	$0					$67	$2	$11	$0	$1,750	$266	$7	$690	$2,884
2033	$0					$72	$3	$12	$0	$1,766	$284	$6	$767	$2,998
2034	$0					$191	$10	$57	$109	$1,818	$290	$3	$794	$3,358
2035	$0					$271	$15	$362	$187	$1,881	$304	$2	$850	$3,954
2036	$0					$263	$15	$353	$187	$1,939	$322	$2	$1,035	$4,196
2037	$0					$255	$16	$343	$187	$2,101	$360	$2	$1,220	$4,562
2038	$0					$284	$18	$341	$229	$2,221	$382	$2	$1,409	$4,964
2039	$0					$301	$20	$336	$260	$2,304	$422	$2	$1,613	$5,335
2040	$0					$304	$21	$329	$275	$2,426	$430	$2	$1,807	$5,668
2041	$0					$304	$22	$321	$285	$2,544	$456	$2	$2,013	$6,020
2042	$0					$379	$29	$353	$371	$2,602	$464	$2	$2,165	$6,434
2043	$0					$428	$33	$673	$432	$2,663	$485	$2	$2,344	$7,127
2044	$0					$441	$36	$659	$465	$2,805	$499	$2	$2,561	$7,532
2045	$0					$460	$39	$646	$505	$2,982	$530	$2	$2,764	$7,990
2046	$0					$456	$41	$628	$517	$3,133	$546	$2	$2,985	$8,368
2047	$0					$442	$42	$609	$517	$3,176	$572	$2	$3,164	$8,581
2048	$0					$428	$43	$590	$517	$3,310	$592	$2	$3,371	$8,912
2049	$0					$415	$44	$572	$517	$3,354	$615	$2	$3,542	$9,113
2050	$0					$403	$45	$553	$517	$3,435	$634	$2	$3,774	$9,399
2051	$0					$391	$46	$534	$517	$3,553	$665	$2	$3,997	$9,728
2052	$0					$378	$47	$516	$517	$3,674	$679	$2	$4,224	$10,042
2053	$0					$366	$48	$497	$517	$3,744	$709	$2	$4,391	$10,278
	$0.0					**$1,740.4**	**$130.8**	**$1,986.7**	**$1,539.7**	**$22,836.7**	**$3,573.4**	**$72.2**	**$11,830.5**	**$45,030.9**

Discount Rate 6.70%

- Negative ( ) Indicates Savings to DEF Customers.

Clean Energy Connection - Mid Fuel & Mid CO_2

		Solar Revenue Requirements				Non-Solar Generation Revenue Requirements				System Revenue Requirements				
Year	Program Admin. Costs (Millions)	Generation Capital (Millions)	Transmission Interconnection (Millions)	Fixed O&M (Millions)	Capital Lease (Millions)	Generation Capital (Millions)	Fixed O&M (Millions)	Transmission Interconnection (Millions)	Incremental Gas Transport (Millions)	System Net Fuel (Millions)	Startup + VOM (Millions)	Environmental Costs without CO_2 (Millions)	CO_2 Emission (Millions)	Total RevReq (Millions)
2020	$0	[redacted]				$0	$0	$0	$0	$850	$86	$6	$0	$1,007
2021	$1	[redacted]				$0	$0	$0	$0	$859	$91	$6	$0	$1,060
2022	$1	[redacted]				$0	$0	$0	$0	$875	$98	$6	$0	$1,151
2023	$1	[redacted]				$0	$0	$0	$0	$878	$103	$6	$0	$1,208
2024	$1	[redacted]				$0	$0	$0	$0	$865	$112	$5	$0	$1,249
2025	$1	[redacted]				$0	$0	$0	$0	$924	$125	$6	$98	$1,405
2026	$1	[redacted]				$0	$0	$0	$0	$1,004	$146	$6	$176	$1,565
2027	$1	[redacted]				$9	$0	$2	$0	$1,130	$166	$6	$256	$1,786
2028	$1	[redacted]				$15	$0	$3	$0	$1,303	$189	$7	$344	$2,071
2029	$1	[redacted]				$24	$1	$4	$0	$1,410	$203	$8	$426	$2,280
2030	$1	[redacted]				$30	$1	$5	$0	$1,507	$226	$8	$516	$2,492
2031	$0	[redacted]				$39	$1	$6	$0	$1,572	$246	$8	$583	$2,650
2032	$0	[redacted]				$45	$1	$7	$0	$1,678	$259	$7	$665	$2,853
2033	$0	[redacted]				$54	$2	$9	$0	$1,693	$279	$6	$739	$2,965
2034	$0	[redacted]				$168	$8	$53	$83	$1,739	$283	$3	$761	$3,277
2035	$0	[redacted]				$239	$13	$356	$142	$1,803	$297	$2	$814	$3,842
2036	$0	[redacted]				$244	$14	$349	$156	$1,860	$317	$2	$993	$4,105
2037	$0	[redacted]				$245	$14	$341	$166	$2,013	$357	$2	$1,170	$4,474
2038	$0	[redacted]				$262	$16	$337	$194	$2,131	$375	$2	$1,352	$4,838
2039	$0	[redacted]				$272	$18	$330	$214	$2,209	$415	$2	$1,546	$5,172
2040	$0	[redacted]				$276	$19	$323	$229	$2,327	$423	$2	$1,733	$5,492
2041	$0	[redacted]				$277	$20	$316	$240	$2,442	$450	$2	$1,932	$5,832
2042	$0	[redacted]				$353	$26	$348	$325	$2,502	$457	$2	$2,081	$6,243
2043	$0	[redacted]				$402	$31	$668	$386	$2,557	$478	$2	$2,252	$6,920
2044	$0	[redacted]				$416	$33	$654	$419	$2,700	$493	$2	$2,467	$7,325
2045	$1	[redacted]				$436	$36	$641	$460	$2,871	$522	$2	$2,663	$7,765
2046	$0	[redacted]				$445	$38	$626	$489	$3,021	$538	$2	$2,878	$8,169
2047	$0	[redacted]				$441	$40	$609	$502	$3,065	$567	$2	$3,054	$8,407
2048	$0	[redacted]				$428	$41	$590	$502	$3,188	$584	$2	$3,248	$8,707
2049	$0	[redacted]				$415	$42	$571	$502	$3,239	$607	$2	$3,421	$8,916
2050	$0	[redacted]				$402	$43	$553	$502	$3,316	$626	$2	$3,645	$9,189
2051	$1	[redacted]				$390	$44	$534	$502	$3,425	$671	$2	$3,854	$9,508
2052	$0	[redacted]				$378	$45	$515	$502	$3,565	$673	$2	$4,101	$9,841
2053	$0	[redacted]				$366	$46	$497	$502	$3,688	$704	$2	$4,325	$10,166
	$7.3	[redacted]				**$1,581.7**	**$118.8**	**$1,957.8**	**$1,385.8**	**$22,009.8**	**$3,508.9**	**$70.9**	**$11,396.4**	**$44,498.2**

Net Difference - Mid Fuel & Mid CO_2

		Solar Revenue Requirements Avoided				Non-Solar Generation Revenue Requirements Avoided				System Revenue Requirements Avoided				
Year	Program Admin. Costs (Millions)	Generation Capital (Millions)	Transmission Interconnection (Millions)	Fixed O&M (Millions)	Capital Lease (Millions)	Generation Capital (Millions)	Fixed O&M (Millions)	Transmission Interconnection (Millions)	Incremental Gas Transport (Millions)	System Net Fuel (Millions)	Startup + VOM (Millions)	Environmental Costs without CO_2 (Millions)	CO_2 Emission (Millions)	Total RevReq (Millions)
2020	$0	[redacted]				$0	$0	$0	$0	$0	$0	$0	$0	$0
2021	$1	[redacted]				$0	$0	$0	$0	$0	$0	$0	$0	$1
2022	$1	[redacted]				$0	$0	$0	$0	($8)	($1)	($0)	$0	$22
2023	$1	[redacted]				$0	$0	$0	$0	($24)	($4)	($0)	$0	$60
2024	$1	[redacted]				$0	$0	$0	$0	($48)	($5)	($0)	$0	$85
2025	$1	[redacted]				$0	$0	$0	$0	($49)	($4)	($0)	($5)	$74
2026	$1	[redacted]				$0	$0	$0	$0	($52)	($5)	($0)	($8)	$61
2027	$1	[redacted]				($9)	($0)	($2)	$0	($57)	($5)	($0)	($11)	$29
2028	$1	[redacted]				($25)	($1)	($4)	$0	($57)	($6)	($0)	($14)	$2
2029	$1	[redacted]				($21)	($1)	($3)	$0	($67)	($5)	($0)	($20)	($12)
2030	$1	[redacted]				($23)	($1)	($4)	$0	($62)	($6)	$0	($18)	($11)
2031	$0	[redacted]				($20)	($1)	($3)	$0	($73)	($7)	$0	($22)	($25)
2032	$0	[redacted]				($22)	($1)	($4)	$0	($72)	($6)	$0	($25)	($31)
2033	$0	[redacted]				($18)	($1)	($3)	$0	($74)	($6)	$0	($28)	($33)
2034	$0	[redacted]				($23)	($2)	($4)	($26)	($79)	($7)	($0)	($33)	($80)
2035	$0	[redacted]				($32)	($2)	($6)	($44)	($78)	($7)	($0)	($35)	($112)
2036	$0	[redacted]				($19)	($2)	($4)	($31)	($79)	($5)	($0)	($42)	($91)
2037	$0	[redacted]				($10)	($1)	($2)	($21)	($88)	($2)	($0)	($50)	($88)
2038	$0	[redacted]				($22)	($2)	($4)	($35)	($90)	($7)	($0)	($57)	($126)
2039	$0	[redacted]				($29)	($3)	($6)	($45)	($95)	($7)	($0)	($67)	($164)
2040	$0	[redacted]				($28)	($3)	($5)	($45)	($99)	($7)	($0)	($74)	($176)
2041	$0	[redacted]				($27)	($3)	($5)	($45)	($102)	($7)	($0)	($81)	($188)
2042	$0	[redacted]				($27)	($3)	($5)	($45)	($100)	($7)	($0)	($84)	($191)
2043	$0	[redacted]				($26)	($3)	($5)	($45)	($106)	($8)	($0)	($92)	($206)
2044	$0	[redacted]				($25)	($3)	($5)	($45)	($104)	($6)	($0)	($94)	($207)
2045	$1	[redacted]				($24)	($3)	($5)	($45)	($111)	($8)	($0)	($101)	($225)
2046	$0	[redacted]				($10)	($2)	($2)	($28)	($113)	($8)	($0)	($106)	($199)
2047	$0	[redacted]				($1)	($2)	($0)	($16)	($111)	($4)	($0)	($109)	($174)
2048	$0	[redacted]				($1)	($2)	($0)	($16)	($122)	($8)	($0)	($123)	($205)
2049	$0	[redacted]				($1)	($2)	($0)	($16)	($115)	($7)	($0)	($121)	($197)
2050	$0	[redacted]				($1)	($2)	($0)	($16)	($119)	($7)	($0)	($128)	($210)
2051	$1	[redacted]				($1)	($2)	($0)	($16)	($128)	$6	($0)	($144)	($220)
2052	$0	[redacted]				($0)	($2)	($0)	($16)	($108)	($6)	($0)	($123)	($201)
2053	$0	[redacted]				($0)	($2)	($0)	($16)	($56)	($5)	($0)	($65)	($113)
	$7.3	[redacted]				**($158.7)**	**($12.0)**	**($28.9)**	**($153.9)**	**($826.9)**	**($64.6)**	**($1.3)**	**($434.1)**	**($532.7)**

Year	No CEC Program Total Rev. Req.	CEC Program Total Rev. Req.	Difference Total Rev. Req.	CEC Program Charges (Millions)	CEC Program Credits (Millions)	General Body of Customers Cost (Savings)	Total Billed MWh	Annual Retail Rate Impact $/1,000 kWh
2021	$1,059	$1,060	$1	$0	$0	$1	39,857,384	0.03
2022	$1,129	$1,151	$22	($15)	$15	$22	40,227,760	0.54
2023	$1,148	$1,208	$60	($45)	$45	$59	40,513,294	1.46
2024	$1,164	$1,249	$85	($75)	$74	$84	40,703,718	2.07
2025	$1,331	$1,405	$74	($75)	$75	$74	41,205,631	1.79
2026	$1,504	$1,565	$61	($75)	$76	$62	41,188,409	1.50
2027	$1,757	$1,786	$29	($75)	$76	$30	41,513,413	0.72
2028	$2,069	$2,071	$2	($75)	$77	$4	42,152,270	0.10
2029	$2,292	$2,280	($12)	($75)	$78	($9)	42,481,081	(0.21)
2030	$2,503	$2,492	($11)	($75)	$78	($8)	42,694,826	(0.18)
2031	$2,675	$2,650	($25)	($75)	$79	($21)	43,306,946	(0.48)
2032	$2,884	$2,853	($31)	($75)	$80	($26)	43,305,627	(0.59)
2033	$2,998	$2,965	($33)	($75)	$81	($28)	44,128,573	(0.63)
2034	$3,358	$3,277	($80)	($75)	$81	($74)	44,458,159	(1.66)
2035	$3,954	$3,842	($112)	($75)	$82	($105)	44,917,813	(2.34)
2036	$4,196	$4,105	($91)	($75)	$83	($83)	45,464,126	(1.83)
2037	$4,562	$4,474	($88)	($75)	$84	($79)	45,732,122	(1.73)
2038	$4,964	$4,838	($126)	($75)	$85	($116)	46,200,854	(2.52)
2039	$5,335	$5,172	($164)	($75)	$85	($153)	46,789,936	(3.27)
2040	$5,668	$5,492	($176)	($75)	$86	($165)	47,259,984	(3.49)
2041	$6,020	$5,832	($188)	($75)	$87	($176)	47,721,196	(3.68)
2042	$6,434	$6,243	($191)	($75)	$88	($178)	48,407,906	(3.68)
2043	$7,127	$6,920	($206)	($75)	$89	($193)	48,611,413	(3.96)
2044	$7,532	$7,325	($207)	($75)	$90	($192)	49,059,789	(3.92)
2045	$7,990	$7,765	($225)	($75)	$91	($210)	49,806,440	(4.21)
2046	$8,368	$8,169	($199)	($75)	$91	($183)	50,128,610	(3.64)
2047	$8,581	$8,407	($174)	($75)	$92	($157)	50,128,610	(3.13)
2048	$8,912	$8,707	($205)	($75)	$93	($187)	50,245,691	(3.72)
2049	$9,113	$8,916	($197)	($75)	$94	($178)	50,128,610	(3.55)
2050	$9,399	$9,189	($210)	($75)	$95	($190)	50,128,610	(3.79)
2051	$9,728	$9,508	($220)	($75)	$96	($199)	50,128,610	(3.97)
2052	$10,042	$9,841	($201)	($60)	$77	($185)	50,245,691	(3.67)
2053	$10,278	$10,166	($113)	($30)	$38	($105)	50,128,610	(2.09)

EXHIBIT NO. LULAC-61

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: CEC 749MW Model Case - Settlement (Filing) from DEF's RESPONSE to LULAC'S FIRST SET of INTERROGATORIES (NOS. 1-8)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 29
PARTY: LULAC
DESCRIPTION: LULAC-61 – DEF Resp to LULAC 1 ROG - CEC 749MW Model Case - Settlement (Filing)

DEF CEC Program

C&I and Residential Program Analysis

C&I and Residential Carve-Out: 96.5%

% of Allocated Revenue Requirement

100.00%

Program View

Calendar Year	Production Year	Capacity (MW)	Production (MWh)	Subscription Fee $/kW/Month	Annual Subscription Fees	Credit Escalator	Credit cents/kWh	Annual Credit	Cost/(Savings) Annual	Cost/(Savings) Cumulative	Revenue Requirements	Variable Benefits
2020		0	0	0.00	$0		0	$0	$0	$0	$0	$0
2021		0	0	0.00	$0		0	$0	$0	$0	$984,631	$0
2022	1	144.59445	354700	8.35	$14,488,364	0.00%	-4.0370	($14,319,256)	$169,108	$169,108	$30,391,476	-$9,532,345
2023	2	433.78335	1062316	8.35	$43,465,092	0.00%	-4.0370	($42,885,678)	$579,413	$748,521	$84,704,853	-$27,416,844
2024	3	722.97225	1770587	8.35	$72,441,819	0.00%	-4.0370	($71,478,599)	$963,221	$1,711,742	$134,166,080	-$52,626,418
2025	4	722.97225	1757556	8.35	$72,441,819	1.50%	-4.0980	($72,024,651)	$417,168	$2,128,910	$127,410,321	-$52,077,385
2026	5	722.97225	1748782	8.35	$72,441,819	1.50%	-4.1590	($72,731,845)	-$290,025	$1,838,885	$121,465,897	-$55,186,446
2027	6	722.97225	1740027	8.35	$72,441,819	1.50%	-4.2210	($73,446,549)	-$1,004,729	$834,156	$109,013,620	-$60,635,386
2028	7	722.97225	1735423	8.35	$72,441,819	1.50%	-4.2840	($74,345,520)	-$1,903,701	-$1,069,545	$105,290,093	-$61,635,865
2029	8	722.97225	1722662	8.35	$72,441,819	1.50%	-4.3480	($74,901,360)	-$2,459,540	-$3,529,086	$102,350,453	-$70,860,613
2030	9	722.97225	1714052	8.35	$72,441,819	1.50%	-4.4130	($75,641,130)	-$3,199,310	-$6,728,396	$99,870,160	-$66,367,804
2031	10	722.97225	1705481	8.35	$72,441,819	1.50%	-4.4790	($76,388,490)	-$3,946,671	-$10,675,067	$97,379,534	-$77,857,444
2032	11	722.97225	1700973	8.35	$72,441,819	1.50%	-4.5460	($77,326,242)	-$4,884,422	-$15,559,489	$95,123,683	-$75,823,983
2033	12	722.97225	1688454	8.35	$72,441,819	1.50%	-4.6140	($77,905,263)	-$5,463,444	-$21,022,933	$92,929,811	-$77,234,340
2034	13	722.97225	1680027	8.35	$72,441,819	1.50%	-4.6830	($78,675,677)	-$6,233,858	-$27,256,791	$90,595,160	-$83,980,455
2035	14	722.97225	1671639	8.35	$72,441,819	1.50%	-4.7530	($79,453,014)	-$7,011,194	-$34,267,985	$88,403,131	-$82,534,935
2036	15	722.97225	1667228	8.35	$72,441,819	1.50%	-4.8240	($80,427,082)	-$7,985,262	-$42,253,248	$86,269,795	-$81,905,913
2037	16	722.97225	1654969	8.35	$72,441,819	1.50%	-4.8960	($81,027,301)	-$8,585,482	-$50,838,729	$84,036,323	-$88,051,673
2038	17	722.97225	1646688	8.35	$72,441,819	1.50%	-4.9690	($81,823,904)	-$9,382,085	-$60,220,814	$87,822,767	-$94,332,405
2039	18	722.97225	1638454	8.35	$72,441,819	1.50%	-5.0440	($82,643,618)	-$10,201,798	-$70,422,612	$85,176,997	-$99,268,193
2040	19	722.97225	1634139	8.35	$72,441,819	1.50%	-5.1200	($83,667,932)	-$11,226,112	-$81,648,725	$82,422,628	-$103,145,892
2041	20	722.97225	1622103	8.35	$72,441,819	1.50%	-5.1970	($84,300,673)	-$11,858,854	-$93,507,579	$79,750,675	-$105,929,578
2042	21	722.97225	1613985	8.35	$72,441,819	1.50%	-5.2750	($85,137,702)	-$12,695,883	-$106,203,461	$77,331,343	-$104,867,768
2043	22	722.97225	1605915	8.35	$72,441,819	1.50%	-5.3540	($85,980,710)	-$13,538,890	-$119,742,351	$75,038,550	-$110,554,498
2044	23	722.97225	1601697	8.35	$72,441,819	1.50%	-5.4340	($87,036,228)	-$14,594,409	-$134,336,760	$72,860,821	-$107,277,415
2045	24	722.97225	1589921	8.35	$72,441,819	1.50%	-5.5160	($87,700,053)	-$15,258,233	-$149,594,993	$70,671,452	-$116,380,496
2046	25	722.97225	1581968	8.35	$72,441,819	1.50%	-5.5990	($88,574,362)	-$16,132,543	-$165,727,536	$68,537,524	-$117,804,996
2047	26	722.97225	1574062	8.35	$72,441,819	1.50%	-5.6830	($89,453,951)	-$17,012,132	-$182,739,667	$66,483,913	-$112,577,530
2048	27	722.97225	1569468	8.35	$72,441,819	1.50%	-5.7680	($90,526,888)	-$18,085,068	-$200,824,736	$64,476,689	-$126,880,558
2049	28	722.97225	1558329	8.35	$72,441,819	1.50%	-5.8550	($91,240,137)	-$18,798,318	-$219,623,053	$62,446,932	-$119,636,849
2050	29	722.97225	1550558	8.35	$72,441,819	1.50%	-5.9430	($92,149,679)	-$19,707,860	-$239,330,913	$60,510,812	-$122,923,799
2051	30	722.97225	1542817	8.35	$72,441,819	1.50%	-6.0320	($93,062,721)	-$20,620,901	-$259,951,815	$62,169,973	-$119,052,948
2052	31	578.3778	1232422	8.35	$57,953,456	0.00%	-6.0320	($74,339,668)	-$16,386,212	-$276,338,027	$52,977,282	-$111,568,274
2053	32	289.1889	611930	8.35	$28,976,728	0.00%	-6.0320	($36,911,611)	-$7,934,883	-$284,272,910	$30,664,979	-$59,535,665
2054	33	0	0	0.00								

C&I/Res - PARAMETERS

	Subscription Fee:	$8.35
	Credit:	-4.0370
	Credit Escalator:	1.50%
	Capital Deferral	$353,458,777
	Discount Rate:	6.70%
	Capacity Factor:	28.00%
	Degradation Rate:	0.50%
$37,870,503.67	% Participants Pay of NPVRR:	104.940%

Totals - C&I and Residential

NPV (RR)	$1,107,743,573
NPV (RR) less Cap. Deferral	$804,437,992
NPV (Sub. Costs)	$804,438,031
NPV (Benefits)	($869,663,216)
NPV (Credit to Participants)	($869,663,141)

	Include Carbon Benefit (Y/N)	N
	% of Variable Benefits	100.92%
Always included	Include Program Admin. Costs (Y/N)	Y

Program Benefits - C&I Res	**NPV - $MMs**	**% of Total**
Capital Deferral	$341.18	21.0%
Fuel	$798.14	49.2%
Variable O&M	$62.31	3.8%
Emissions	$1	0.1%
Carbon	$419	25.8%
Total	$1,621.96	
Program Costs - C&I Res		
Solar Rev Req	$1,101	99.4%
Admin Costs	$7	0.6%
Total	$1,108	
Total Program Savings	$514	
Participant Savings	$65	12.7%
Non-Participant Savings	$449	87.3%
Program Savings (Non-Carbon)	$95	
Participant Savings	$65	68.5%
Non-Participant Savings	$30	31.5%

Tariff Schedule - C&I and Residential

Program Year	Subscription Fee ($/kW-mo)	Credit (cents/kWH)	Credit Esc (%/yr)
1	$8.35	-4.0370	
2	$8.35	-4.0370	0.0%
3	$8.35	-4.0370	0.0%
4	$8.35	-4.0980	1.5%
5	$8.35	-4.1590	1.5%
6	$8.35	-4.2210	1.5%
7	$8.35	-4.2840	1.5%
8	$8.35	-4.3480	1.5%
9	$8.35	-4.4130	1.5%
10	$8.35	-4.4790	1.5%
11	$8.35	-4.5460	1.5%
12	$8.35	-4.6140	1.5%
13	$8.35	-4.6830	1.5%
14	$8.35	-4.7530	1.5%
15	$8.35	-4.8240	1.5%
16	$8.35	-4.8960	1.5%
17	$8.35	-4.9690	1.5%
18	$8.35	-5.0440	1.5%
19	$8.35	-5.1200	1.5%
20	$8.35	-5.1970	1.5%
21	$8.35	-5.2750	1.5%
22	$8.35	-5.3540	1.5%
23	$8.35	-5.4340	1.5%
24	$8.35	-5.5160	1.5%
25	$8.35	-5.5990	1.5%
26	$8.35	-5.6830	1.5%
27	$8.35	-5.7680	1.5%
28	$8.35	-5.8550	1.5%
29	$8.35	-5.9430	1.5%
30	$8.35	-6.0320	1.5%
31	$8.35	-6.0320	0.0%
32	$8.35	-6.0320	0.0%

PAYBACK CHECK

Year	MW	MWh	Sub Fee	Credit	Annual	Cumulative
1	1	2453.071	100.2	-99.0305	1.169533	1.169533
2	1	2448.954	100.2	-98.8643	1.335721	2.505254
3	1	2449.039	100.2	-98.8677	1.332307	3.837561
4	1	2431.015	100.2	-99.623	0.577018	4.414579
5	1	2418.879	100.2	-100.601	-0.40116	4.013422
6	1	2406.769	100.2	-101.59	-1.38972	2.623701
7	1	2400.401	100.2	-102.833	-2.63316	-0.00946
8	1	2382.75	100.2	-103.602	-3.40198	-3.41144
9	1	2370.841	100.2	-104.625	-4.42522	-7.83666
10	1	2358.985	100.2	-105.659	-5.45895	-13.2956
11	1	2352.75	100.2	-106.956	-6.75603	-20.0516
12	1	2335.434	100.2	-107.757	-7.55692	-27.6086

EXHIBIT NO. LULAC-45

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: WALMART'S RESPONSES and OBJECTIONS to LULAC'S FIRST SET of INTERROGATORIES (NOS. 1-20)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 30
PARTY: LULAC
DESCRIPTION: LULAC-45 – Walmart Responses and Objections to LULAC Interrogatories - Set 1 (PUBLIC)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.	**:**	**DOCKET NO. 20200176-EI**
	:	**Filed: November 2, 2020**

WALMART INC.'S RESPONSES AND OBJECTIONS TO
LEAGUE OF UNITED LATIN AMERICAN CITIZENS'
FIRST SET OF INTERROGATORIES (NOS. 1-20)

Walmart Inc. ("Walmart") by and through its undersigned counsel, pursuant to Rule 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, and the Florida Public Service Commission's ("Commission") Order Establishing Procedure PSC-2020-0324-PCO-EI hereby serves their Responses and Objections to League of United Latin American Citizens' ("LULAC") First Set of Interrogatories (Nos. 1-20) to Walmart.

GENERAL OBJECTIONS

1. Walmart objects to Definitions No. 1 and No. 5 because they are overly broad and irrelevant to the extent they make a request for discovery of information or documents to entities other than those involved in the instant regulatory proceeding.

2. Walmart objects to each discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. Walmart in no way intends to waive such privilege or protection. Walmart objects to LULAC's instructions to the extent they purport to require Walmart to provide more information, with respect to withheld privileged documents, than required under applicable rules and law.

3. Walmart objects to providing information that is proprietary, confidential business information without provisions in place to protect the confidentiality of the information. Walmart in no way intends to waive claims of confidentiality.

4. Walmart objects to each discovery request that seeks information not relevant to this proceeding and is not reasonably calculated to lead to the discovery of admissible evidence. Walmart expressly reserves, and does not waive, any and all objections to the admissibility, authenticity or relevancy of the information provided in its responses to the discovery requests.

INTERROGATORIES

Walmart incorporates by reference all of the foregoing General Objections into its Specific Objections set forth below as though fully stated herein.

1. On page 8, lines 12-13 of Mr. Chriss's testimony, Mr. Chriss explains that "the parties to the Stipulation engaged in discussions with DEF in order to secure improvements to the planned CEC Program and Tariff." Please explain the nature of these "discussions," including who initiated the discussions and why, and please identify any documents showing how the parties to the Stipulation were able to "secure improvements" from Duke Energy Florida, LLC ("Duke").

   RESPONSE: **Walmart objects to this Interrogatory on the grounds that settlement discussions, including documents exchanged in furtherance of settlement negotiations, are confidential among settling parties. Further, Walmart objects to the extent this Interrogatory seeks privileged and/or work product information that is not discoverable pursuant to Fla. R. Civ. P. 1.280 and F.S. 366.093. The primary issue in this Docket is whether the Stipulation, as filed, is in the public interest, and**

communications and/or documents generated in the negotiations leading up to the execution of the Stipulation are not reasonably calculated to lead to admissible evidence in this Docket and, therefore, Walmart objects to production of the same.

2. On pages 5-6 of Mr. Chriss's testimony, Mr. Chriss references Walmart's participation in utility partnerships to "develop useable commercial and industrial programs," including participating in the development of Florida Power & Light Company's SolarTogether Program. Please explain whether Walmart was involved in the development of Duke's Program. If so, please describe the role and extent Walmart played in the development, including who initiated the discussions and why, the date discussions were initiated, the period of time over which communications were had, and any other specific actions taken toward participating in the development of the Program.

RESPONSE: Walmart objects to this Interrogatory on the grounds that settlement discussions, including documents exchanged in furtherance of settlement negotiations, are confidential among settling parties. Further, Walmart objects to the extent this Interrogatory seeks privileged and/or work product information that is not discoverable pursuant to Fla. R. Civ. P. 1.280 and F.S. 366.093. The primary issue in this Docket is whether the Stipulation, as filed, is in the public interest, and communications and/or documents generated in the negotiations leading up to the execution of the Stipulation are not reasonably calculated to lead to admissible evidence in this Docket and, therefore, Walmart objects to production of the same.

3. In its Petition to Intervene, Walmart explained that it purchases more than 290 million kWh annually from Duke Energy Florida. Please provide how many kWh Walmart has purchased from Duke for each of the last five years.

<u>**RESPONSE:**</u> **Walmart states that it has purchased the following kWh amounts from Duke for each of the last five full calendar years: 2015 – 283,000,000, 2016 – 295,000,000, 2017 – 307,000,000, 2018 – 313,000,000, and 2019 – 297,000,000.**

4. Please explain whether Walmart has preregistered to participate in the Program. If so, please provide the size of the subscription, and please explain how many kWh are projected to be produced annually by that subscription size. Please provide how this compares to Walmart's total kWh annually purchased from Duke as a percent (for example, whether it is expected to cover 100%, 50%, or some other number of Walmart's electricity consumption).

<u>**RESPONSE:**</u> **Walmart will provide this confidential response upon execution of a Non-Disclosure Agreement.**

5. If the Program is approved, please detail how much, on net, Walmart expects to pay or receive as a bill credit each year for participating in the Clean Energy Connection program throughout the life of the Program. Please identify any documents containing this information.

<u>**RESPONSE:**</u> **Walmart objects to this Interrogatory on the grounds that settlement discussions, including documents exchanged in furtherance of settlement negotiations, are confidential among settling parties. Further, Walmart objects to**

the extent this Interrogatory seeks privileged and/or work product information that is not discoverable pursuant to Fla. R. Civ. P. 1.280 and F.S. 366.093. In addition, Walmart objects to this Interrogatory to the extent that it is irrelevant to this Docket and is, therefore, not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b). The primary issue in this Docket is whether the Stipulation, as filed, is in the public interest, and communications and/or documents generated in the negotiations leading up to the execution of the Stipulation are not reasonably calculated to lead to admissible evidence in this Docket and, therefore, Walmart objects to production of the same. Moreover, this Interrogatory seeks information that is commercially sensitive; if this Interrogatory regarding commercially sensitive documents is not withdrawn, absent other valid grounds for objection, Walmart will file a Motion for Protective Order pursuant to Fla. R. Civ. P. 1.280(c).

6. Please provide Walmart's expected return on investment in the Program; specifically, a comparison of how much Walmart expects, on net, to pay during the beginning years of the Program to how much Walmart expects to receive as a bill credit, on net, during the later years of the Program. For example, if Walmart, during the first five years of the Program, expects to pay $100,000 on net to participate, and during the next 26 years of the Program, expects to receive as a bill credit, on net, $20 million, Walmart would expect to receive a 200 to 1 return on its investment.

RESPONSE: **Walmart objects to this Interrogatory on the grounds that settlement discussions, including documents exchanged in furtherance of settlement**

negotiations, are confidential among settling parties. Further, Walmart objects to the extent this Interrogatory seeks privileged and/or work product information that is not discoverable pursuant to Fla. R. Civ. P. 1.280 and F.S. 366.093. In addition, Walmart objects to this Interrogatory to the extent that it is irrelevant to this Docket and is, therefore, not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b). The primary issue in this Docket is whether the Stipulation, as filed, is in the public interest, and communications and/or documents generated in the negotiations leading up to the execution of the Stipulation are not reasonably calculated to lead to admissible evidence in this Docket and, therefore, Walmart objects to production of the same. Moreover, this Interrogatory seeks information that is commercially sensitive; if this Interrogatory regarding commercially sensitive documents is not withdrawn, absent other valid grounds for objection, Walmart will file a Motion for Protective Order pursuant to Fla. R. Civ. P. 1.280(c).

7. Please identify all of the other "[u]tility partnerships" (as that term is used on page 5, line 8 of Mr. Chriss's testimony) that Walmart participates in and provide Walmart's expected return on investment for each partnership. Please identify any document containing this information.

<u>RESPONSE:</u> **Walmart objects to this Interrogatory request for "Walmart's expected return on investment for each partnership" because it is irrelevant to this Docket, is not likely reasonably calculated to lead to the discovery of admissible**

evidence pursuant to Fla. R. Civ. P. 1.280(b). Moreover, this Interrogatory seeks information that is commercially sensitive; if this Interrogatory regarding commercially sensitive documents is not withdrawn, absent other valid grounds for objection, Walmart will file a Motion for Protective Order pursuant to Fla. R. Civ. P. 1.280(c). Without waiving its objections, Walmart states that other utility partnerships in which Walmart is involved are as follows:

Alabama Power – Alabama Solar A Solar Farm

Salt River Project – Renewable Energy Offering

Xcel-Public Service Company of Colorado – Renewable*Connect

Florida Power & Light – SolarTogether

Georgia Power – C&I REDI Program

Evergy Kansas – Renewables Direct

PNM – Solar Direct

Black Hills Energy (SD & WY) – Renewable Ready

Avista Energy (WA) – Solar Select

Puget Sound Energy (WA) – Schedule 139

8. On page 5, line 4 of Mr. Chriss's testimony, Mr. Chriss references "[c]ontracting for onsite resources." Please explain whether Walmart has contracted for on-site resources within Duke's service territory in Florida. If Walmart has not contracted for on-site resources within Duke's service territory in Florida, please explain why Walmart has not done so. If Walmart has contracted for on-site resources within Duke's service territory

in Florida, please provide the amount of such resources, in terms of kW and/or kWh, for which Walmart has contracted.

RESPONSE: **Walmart objects to this Interrogatory request because it is irrelevant to this Docket, seeks commercially sensitive information, and is not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b).**

9. Please explain whether Walmart has contracted for on-site resources outside Duke's service territory in Florida. If Walmart has not contracted for on-site resources outside Duke's service territory in Florida, please explain why Walmart has not done so. If Walmart has contracted for on-site resources outside Duke's service territory in Florida, please provide the amount of such resources in, terms of kW and/or kWh, for which Walmart has contracted.

RESPONSE: **Walmart objects to this Interrogatory request because it is irrelevant to this Docket, seeks commercially sensitive information, and is not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b).**

10. Please provide the total amount of "on-site resources," in terms of kW and/or kWh, for which Walmart has contracted nationwide.

<u>RESPONSE:</u> Walmart objects to this Interrogatory request because it is irrelevant to this Docket, seeks commercially sensitive information, and is not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b).

11. Please explain how the Program factors into Walmart's consideration of whether to contract for "on-site resources" within Duke's service territory in Florida.

<u>RESPONSE:</u> Walmart objects to this Interrogatory request because it is irrelevant to this Docket, seeks commercially sensitive information, and is not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b).

12. Prior to the development of the Program, please explain whether Walmart had any plans to contract for "on-site resources" within Duke's service territory in Florida. Please explain how whether those plans have changed as a result of the development of the Program, and why they have changed.

<u>RESPONSE:</u> Walmart objects to this Interrogatory request because it is irrelevant to this Docket, seeks commercially sensitive information, and is not likely reasonably calculated to lead to the discovery of admissible evidence pursuant to Fla. R. Civ. P. 1.280(b).

13. On page 7, lines 16-19, of Mr. Chriss's testimony, Mr. Chriss explains that the "CEC program is a voluntary community solar program." Please explain whether it is Walmart's understanding that Duke ratepayers who do not volunteer to participate in the Program will pay at all for the Program, and please explain the basis for this belief. If it is Walmart's understanding that non-participants will pay for the Program, please explain how much Walmart believes non-participants will pay for the Program, and please explain the basis for this belief.

RESPONSE: **Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket. Without waiving its objection, Walmart states that it is its understanding that Duke's modeling shows that non-participants will pay some costs and receive some benefits, and that the Company expects that over the life of the Program, the benefits will exceed the costs for non-participating customers. As Duke's witnesses have testified, non-participants will realize $2.9 billion in savings over the life of the Program, and participants will pay 104.9% of fixed revenue requirements associated with the Program.**

14. On page 8, lines 6-7, of Mr. Chriss's testimony, Mr. Chriss explains the allocation of projected savings. Please explain whether it is Walmart's belief that the bill credits to participants are related to the "$533 million in projected savings," and please explain the basis for that belief.

<u>RESPONSE:</u> Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that the information sought by this Interrogatory is contained in DEF's Exhibit TGF-1, which Exhibit speaks for itself.

15. On page 12, lines 3-4, of Mr. Chriss's testimony, Mr. Chriss states that "Walmart believes that the parties' Stipulation in this Docket represents a fair, just, and reasonable resolution of issues." Please explain whether Walmart believes prefiled exhibit TGF-1 represents the Summary of the Clean Energy Connection Program Revenue Requirements, Subscription Fees, and Bill Credits. If not, please explain why not. If Walmart believes exhibit TGF-1 does represent the summary of the program revenue requirements, fees, and credits, please answer the following questions based on exhibit TGF-1:

    a. Is it Walmart's understanding that in the year 2022, participants in the Clean Energy Connection program will, on net, contribute approximately $100,000 towards the costs of the program, while the general body of ratepayers will contribute approximately $21,600,000? If not, please explain all bases for your understanding.

    b. Is it Walmart's understanding that in the year 2023, participants in the Clean Energy Connection program will, on net, contribute approximately $500,000 towards the costs of the program, while the general body of ratepayers will contribute approximately $59,200,000? If not, please explain all bases for your understanding.

c. Is it Walmart's understanding that in the year 2024, participants in the Clean Energy Connection program will, on net, contribute approximately $800,000 towards the costs of the program, while the general body of ratepayers will contribute approximately $84,200,000? If not, please explain all bases for your understanding.

d. Is it Walmart's understanding that in the year 2025, participants in the Clean Energy Connection program will, on net, contribute approximately $200,000 towards the costs of the program, while the general body of ratepayers will contribute approximately $73,700,000? If not, please explain all bases for your understanding.

e. Is it Walmart's understanding that in the year 2026, participants in the Clean Energy Connection program will, on net, receive a bill credit of approximately $500,000 from the program, while the general body of ratepayers will contribute approximately $61,600,000 towards the costs of the program, including the $500,000 bill credit to participants? If not, please explain all bases for your understanding.

f. Is it Walmart's understanding that in the year 2027, participants in the Clean Energy Connection program will, on net, receive a bill credit of approximately $1,200,000 from the program, while the general body of ratepayers will contribute approximately $29,700,000 towards the costs of the program, including the $1,200,000 bill credit to participants? If not, please explain all bases for your understanding.

g. Is it Walmart's understanding that in the year 2028, participants in the Clean Energy Connection program will, on net, receive a bill credit of approximately $2,100,000 from the program, while the general body of ratepayers will contribute approximately $4,200,000 towards the costs of the program, including the $2,100,000 bill credit to participants? If not, please explain all bases for your understanding.

<u>RESPONSE:</u> Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that DEF's Exhibit TGF-1, which Walmart believes represents the Summary of the Clean Energy Connection Program Revenue Requirements, Subscription Fees, and Bill Credits, speaks for itself. Further, Duke's Rebuttal Testimony from witnesses Foster and Huber project $2.9 billion net savings for non-participating customers, while participants shall be responsible for 104.9% of the fixed revenue requirements through such subscription fees.

16. Based on exhibit TGF-1, is it Walmart's understanding that participants in the Program will, on net, receive approximately $290,600,000 in bill credits from the year 2021-2053? If so, is it Walmart's understanding that these bill credits will be recovered through Duke's fuel and purchased power cost recovery clause from the general body of ratepayers? Please explain your answer.

RESPONSE: **Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that DEF's Exhibit TGF-1 speaks for itself, and based on Exhibit TGF-1, participants are projected to receive $290,600,000 net cost subscription fees over thirty years, subject to the solar resources producing at Duke's projected levels. Participants shall be responsible for 104.9% of the fixed revenue requirements through such subscription fees. Further, participants take the risk that the resources do not meet projections, and as such, the bill credits would be lower.**

17. Is it Walmart's understanding that benefits to the general body of customers, as reflected on Exhibit TGF-1, are dependent on assumed system net fuel benefits, emissions benefits, and system benefits? If so, is it Walmart's understanding that if those benefits do not materialize as anticipated, the benefits to the general body of customers will decrease but the bill credits to participants will not be impacted? Please explain your answer and identify any documents supporting your answer.

RESPONSE: **Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that DEF's Exhibit TGF-1 speaks for itself, and based on Exhibit TGF-1, benefits reflected in Exhibit TGF-1 are dependent on assumed net fuel benefits, emissions benefits, and system benefits, as well as on the solar resources producing at the**

levels projected by the Company. Actual production different than the production that is projected will change the values for both participants and non-participants.

18. Based on exhibit TGF-1, is it Walmart's understanding that the Program's administrative costs are $16.8 million (nominal)? Also based on that exhibit, is it Walmart's understanding that participants' net contributions to the costs of the program are $1.6 million (calculated by adding up years 2022-2025, where participants, on net, through subscription fees, contribute to the cost of the program)? Please explain your answer.

<u>**RESPONSE:**</u> **Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that it understands that the Program's administrative costs are $16.8 million for the thirty years of the Program on a nominal basis per DEF witness Foster.**

19. Does Walmart contend that participants in the Program meaningfully (defined here to be more than 1%) contribute to the cost of the program? If so, please explain all bases for this contention and identify all documents supporting this contention.

<u>**RESPONSE:**</u> **Walmart objects to this Interrogatory as it is better directed at Duke, the author of the Program at issue in this Docket, and to its witness, Thomas G. Foster, the author of Exhibit TGF-1. Without waiving its objection, Walmart states that it has not conducted an independent projection of the Program's economics; however, pursuant to Exhibit TGF-1, participants will pay $2.2 billion nominal of**

subscription fees and take on the production risk of the solar resources. Such payments represent 104.9% of the fixed revenue requirements associated with the Program.

20. Does Walmart contend that the Clean Energy Connection program is fair, just, and reasonable to the general body of ratepayers? If so, please explain all bases for this contention and identify all documents supporting this contention.

<u>**RESPONSE:**</u> **Yes. The reasons are set forth in the Company's Petition for a Limited Proceeding to Approve the Program, Tariff and Stipulation and Direct Testimony of Thomas G. Foster, with Exhibits, filed on July 1, 2020, the Company's Rebuttal Testimony filed October 19, 2020, as well as in Walmart's Petition to Intervene filed on September 25, 2020, and Walmart's Direct Testimony and Exhibits filed on October 2, 2020.**

Respectfully submitted this 2nd day of November, 2020.

By */s/Stephanie U. Eaton*

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DECLARATION

I sponsored the Answers to Interrogatory Nos. 3, 4, 7, and 13-20, from League of United Latin American Citizens' First Set of Interrogatories to Walmart Inc. in Docket No. 20200176-EI, and that the responses are true and corrected based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and answers identified above, and that the facts stated therein are true.

Signature

Steve W. Chriss

Date: November 2, 2020

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail to the following parties this 2nd day of November, 2020.

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/s/Stephanie U. Eaton
Stephanie U. Eaton

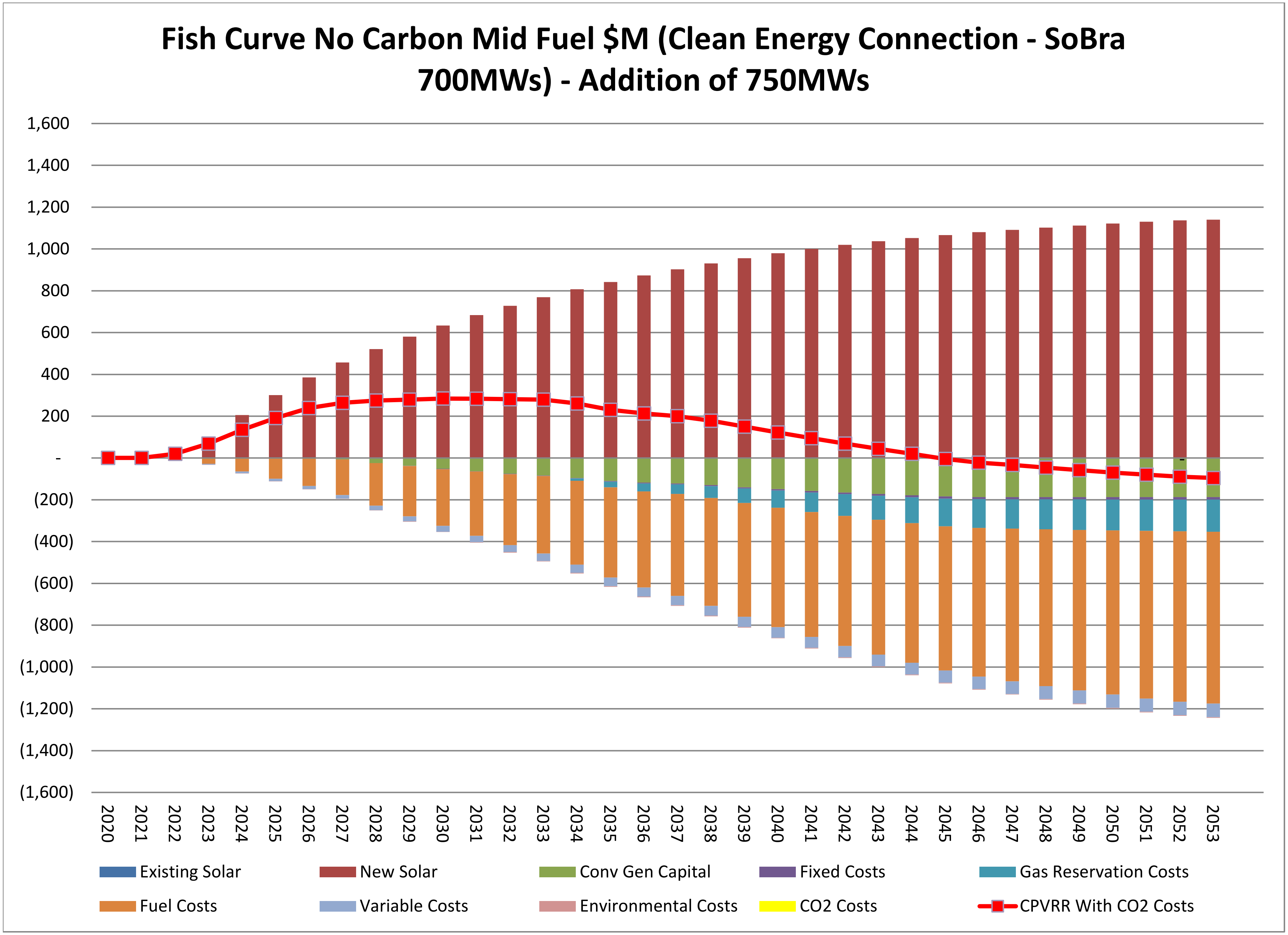
EXHIBIT NO. LULAC-62

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: 2020-05 CEC 750MWs CPVRR Results_05282020 from DEF's RESPONSE to LULAC'S FIRST SET of INTERROGATORIES (NOS. 1-8)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 31
PARTY: LULAC
DESCRIPTION: LULAC-62 – DEF Resp to LULAC ROG 2020-05 CEC_750MWs CPVRR_Results_05282020


Fish Curve No Carbon Mid Fuel $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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Existing Solar
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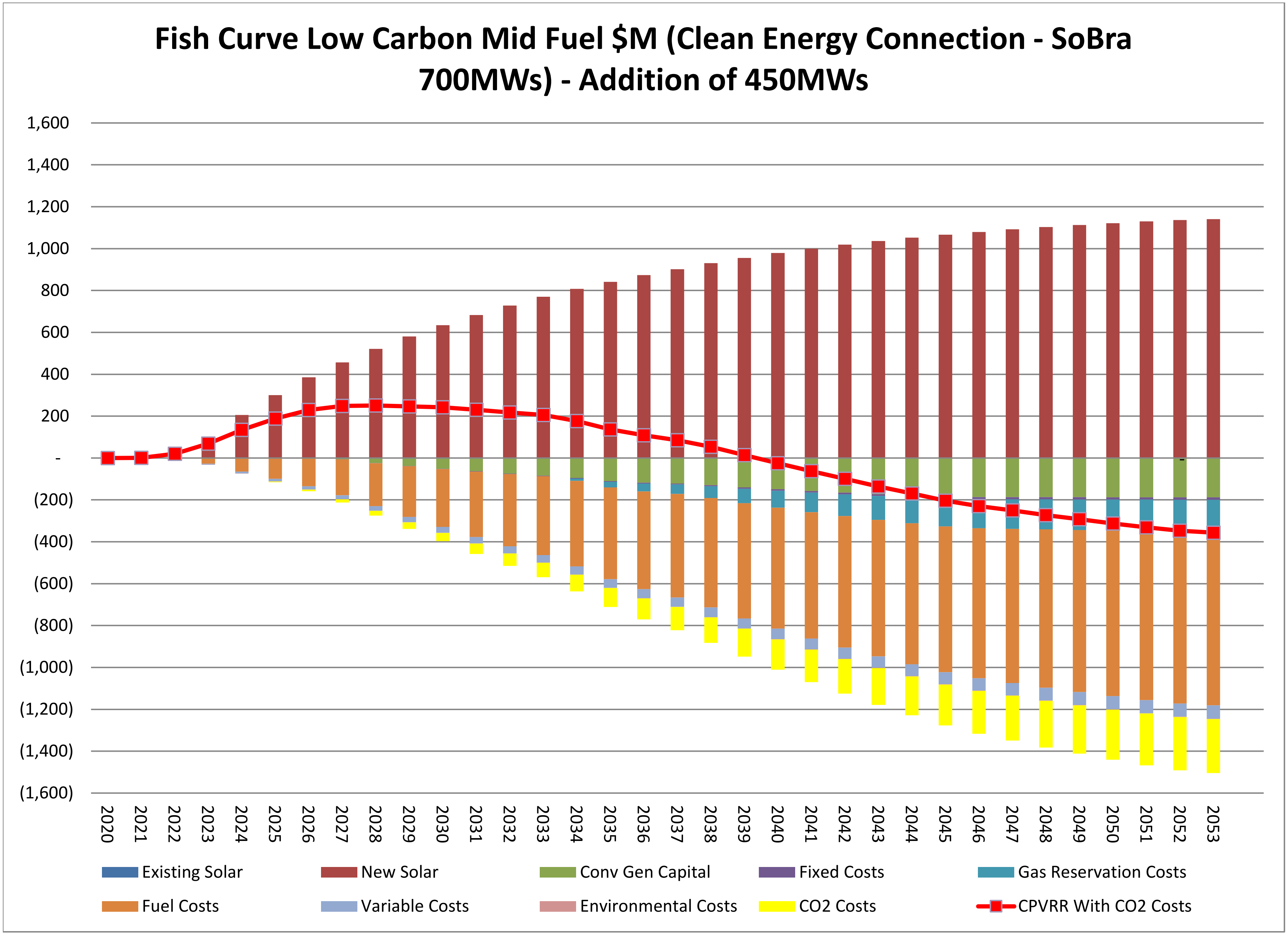
Conv Gen Capital
Fixed Costs
Gas Reservation Costs
Fuel Costs
Variable Costs
Environmental Costs
CO2 Costs
CPVRR With CO2 Costs


Fish Curve Low Carbon Mid Fuel $M (Clean Energy Connection - SoBra 700MWs) - Addition of 450MWs
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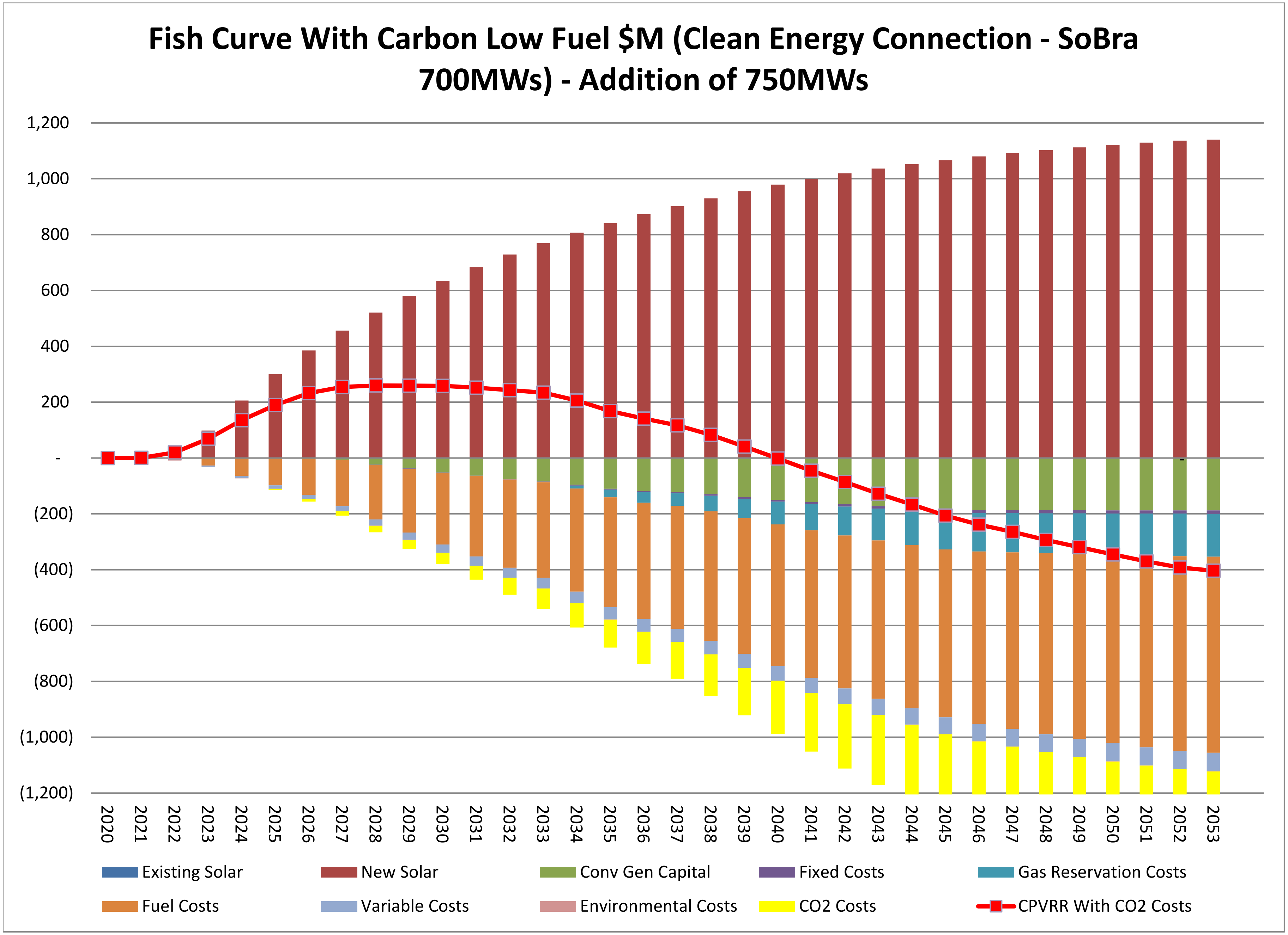
CO2 Costs
CPVRR With CO2 Costs


Fish Curve With Carbon Low Fuel $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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Conv Gen Capital
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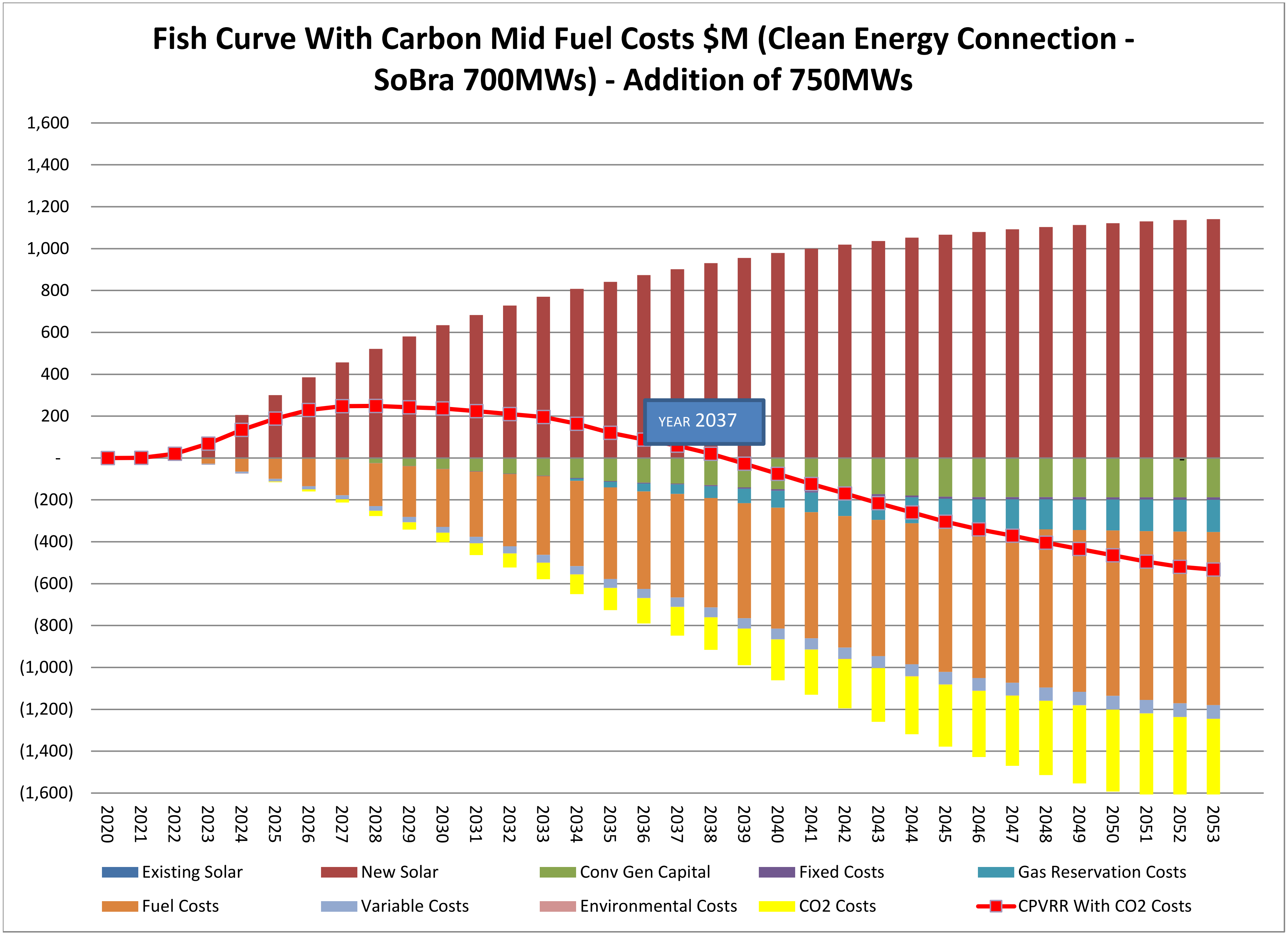
Gas Reservation Costs
Fuel Costs
Variable Costs
Environmental Costs
CO2 Costs
CPVRR With CO2 Costs


Fish Curve With Carbon Mid Fuel Costs $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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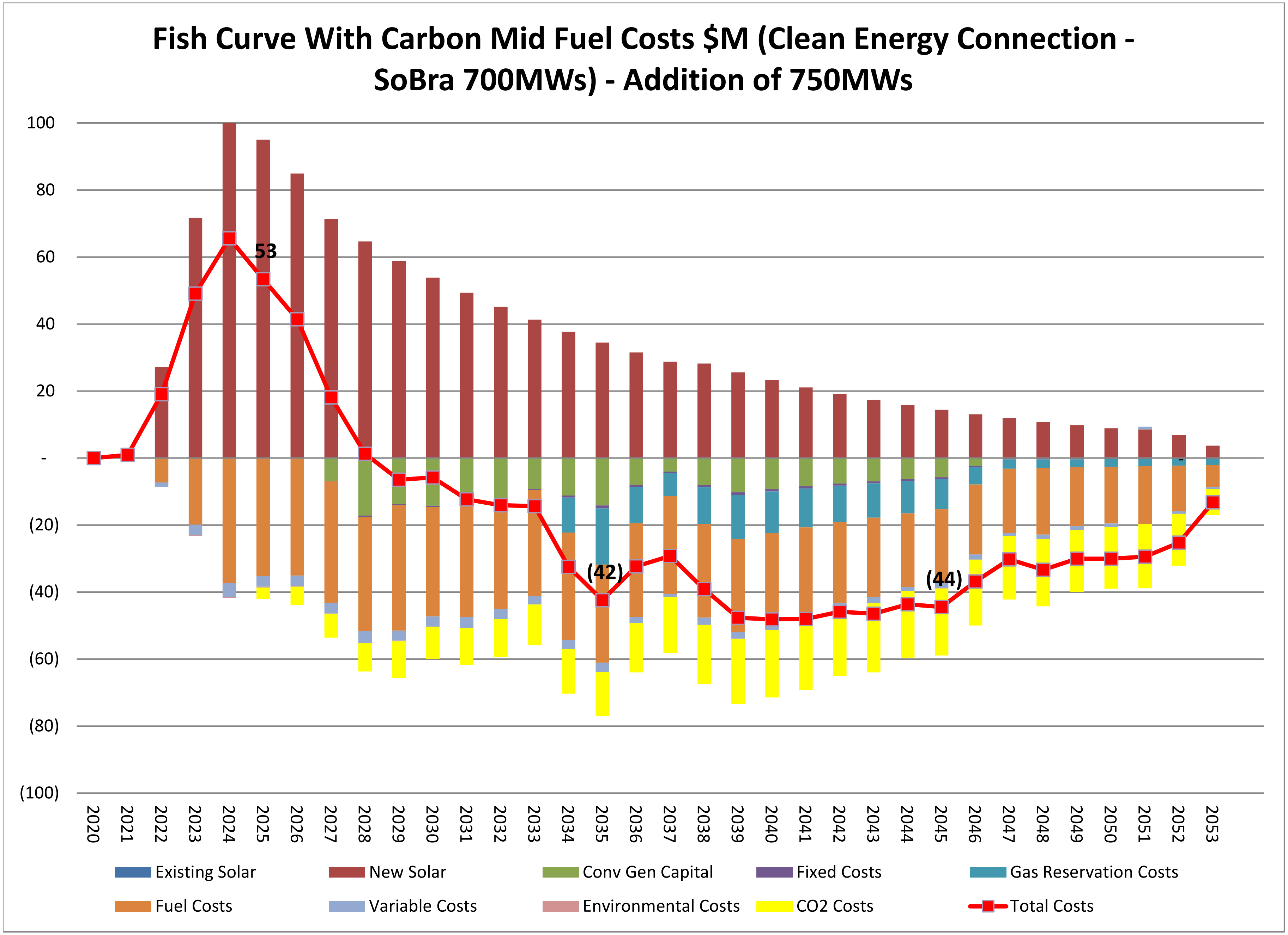
Variable Costs
Environmental Costs
CO2 Costs
CPVRR With CO2 Costs


Fish Curve With Carbon Mid Fuel Costs $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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Variable Costs
Environmental Costs
CO2 Costs
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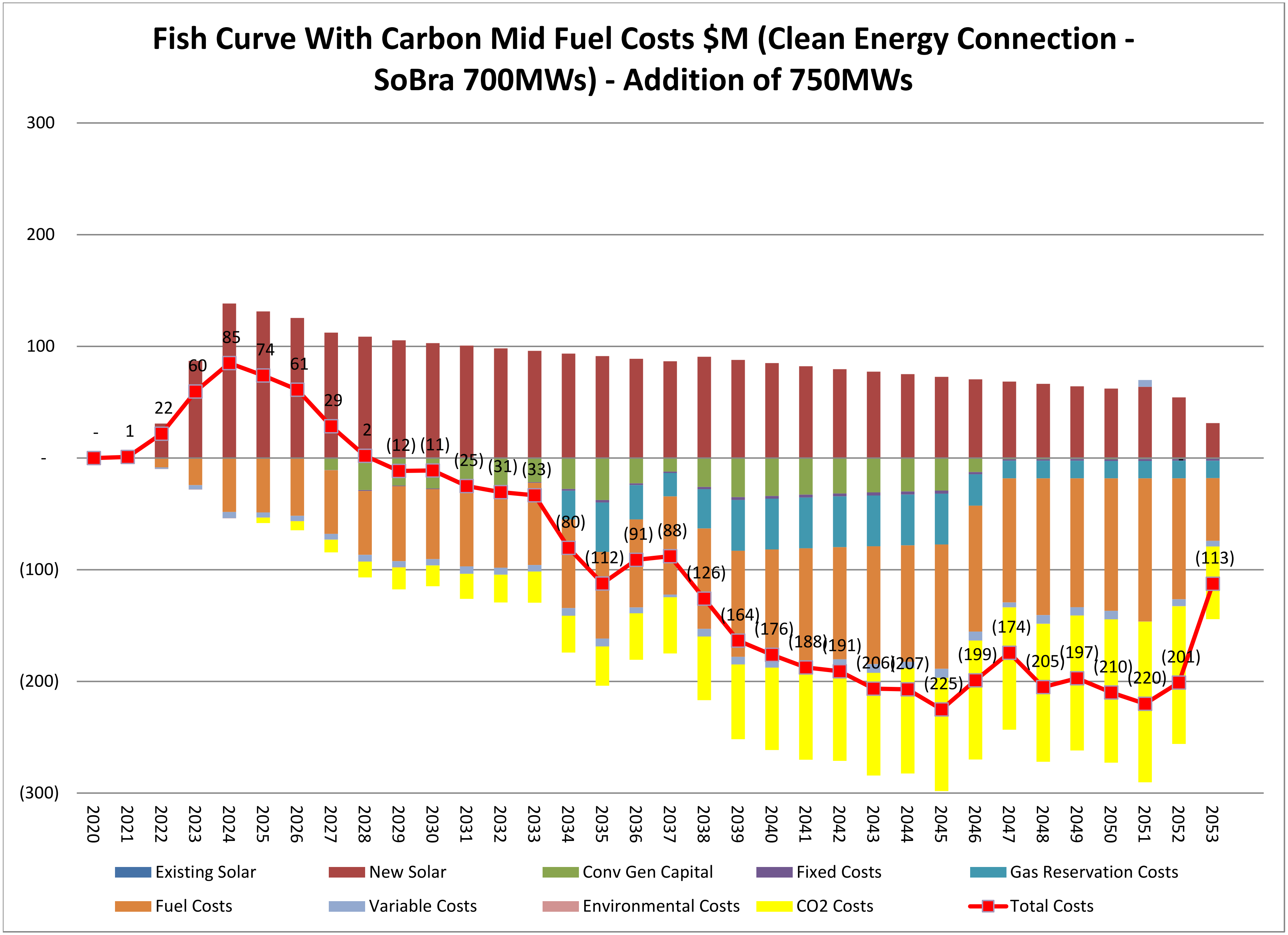
Fish Curve With Carbon Mid Fuel Costs $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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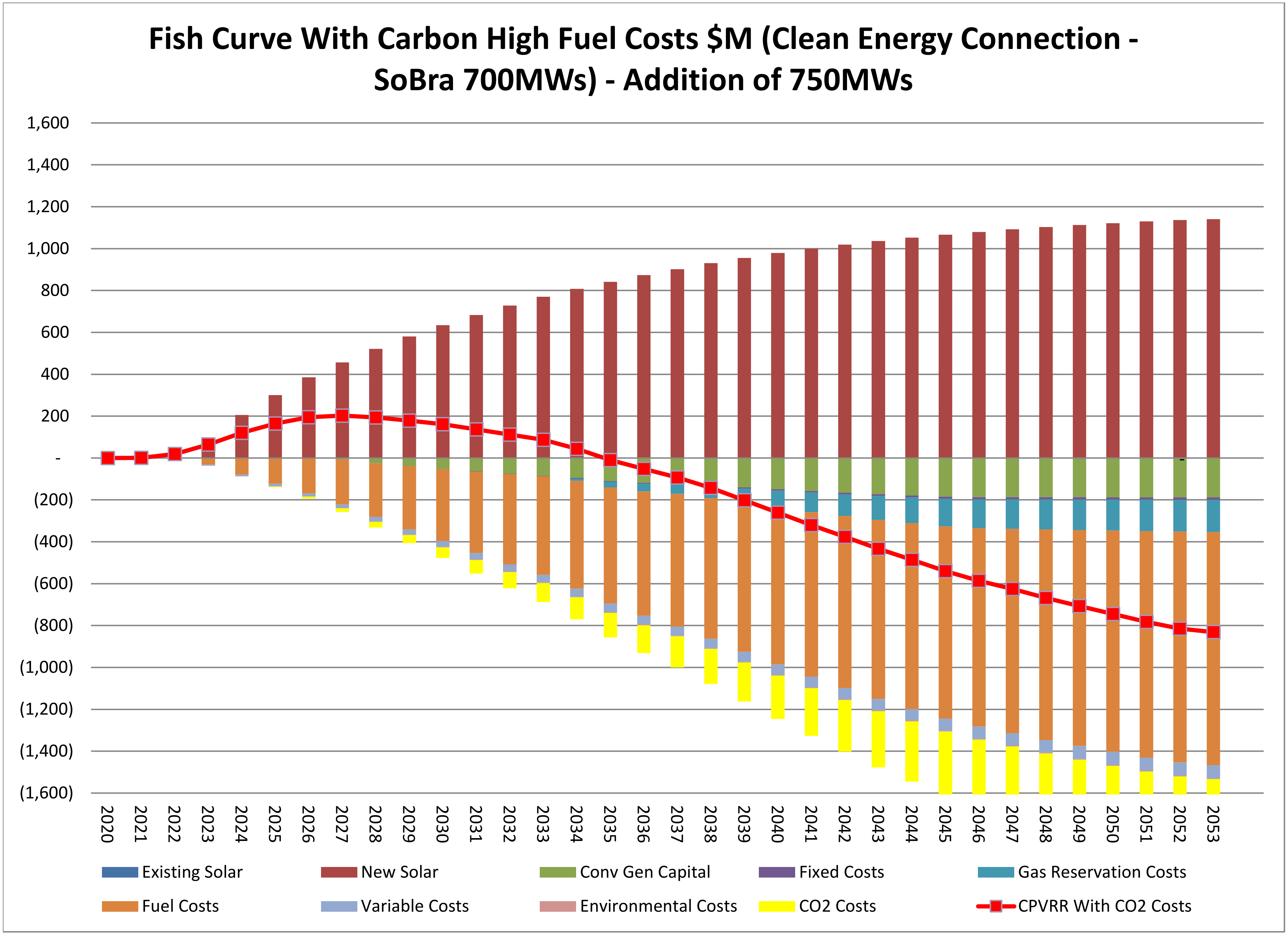
Conv Gen Capital
Fixed Costs
Gas Reservation Costs
Fuel Costs
Variable Costs
Environmental Costs
CO2 Costs
Total Costs


Fish Curve With Carbon High Fuel Costs $M (Clean Energy Connection - SoBra 700MWs) - Addition of 750MWs
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Conv Gen Capital
Fixed Costs
Gas Reservation Costs
Fuel Costs
Variable Costs
Environmental Costs
CO2 Costs
CPVRR With CO2 Costs

CPVRR Through Year 2053 2020$M - Resource Plan through 2046 and extension through 2053 $M	No Carbon Costs_Mid Fuel		Low Carbon Costs_Mid Fuel		With Carbon Costs_Low Fuel		With Carbon Costs_Mid Fuel		With Carbon Costs_High Fuel		Clean Energy Connection 750MWs - SoBra 700MWs				
	SoBra 700MWs	Clean Energy Connection 750MWs	SoBra 700MWs	Clean Energy Connection 750MWs	SoBra 700MWs	Clean Energy Connection 750MWs	SoBra 700MWs	Clean Energy Connection 750MWs	SoBra 700MWs	Clean Energy Connection 750MWs	No Carbon Costs_Mid Fuel	Low Carbon Costs_Mid Fuel	With Carbon Costs_Low Fuel	With Carbon Costs_Mid Fuel	With Carbon Costs_High Fuel
Hamilton	161	161	161	161	161	161	161	161	161	161	-	-	-	-	-
Columbia	156	156	156	156	156	156	156	156	156	156	-	-	-	-	-
Trenton	141	141	141	141	141	141	141	141	141	141	-	-	-	-	-
Lake Placid	87	87	87	87	87	87	87	87	87	87	-	-	-	-	-
Debary	122	122	122	122	122	122	122	122	122	122	-	-	-	-	-
Santa Fe	156	156	156	156	156	156	156	156	156	156	-	-	-	-	-
Twin Rivers	144	144	144	144	144	144	144	144	144	144	-	-	-	-	-
Duette	122	122	122	122	122	122	122	122	122	122	-	-	-	-	-
Charlie Creek	132	132	132	132	132	132	132	132	132	132	-	-	-	-	-
Archer	99	99	99	99	99	99	99	99	99	99	-	-	-	-	-
2022 Clean Energy Connection		259		259		259		259		259	259	259	259	259	259
2023 Clean Energy Connection		454		454		454		454		454	454	454	454	454	454
2024 Clean Energy Connection		427		427		427		427		427	427	427	427	427	427
Conventional Generation (Capital / FOM / Gas Reserv.)	10,782	10,429	10,782	10,429	10,782	10,429	10,782	10,429	10,782	10,429	(353)	(353)	(353)	(353)	(353)
Fuel Cost	22,607	21,785	22,751	21,924	19,703	19,001	22,837	22,010	30,192	29,080	(822)	(828)	(702)	(827)	(1,113)
Variable Costs	3,539	3,474	3,566	3,503	3,570	3,503	3,573	3,509	3,576	3,512	(65)	(63)	(67)	(65)	(64)
Environmental Costs without Carbon	88	85	74	72	67	66	72	71	97	94	(3)	(2)	(0)	(1)	(3)
Adm. Costs		7		7		7		7		7	7	7	7	7	7
Total Solar Savings before CO2 Costs	**38,336**	**38,240**	**38,494**	**38,396**	**35,442**	**35,467**	**38,585**	**38,486**	**45,968**	**45,582**	**(96)**	**(99)**	**25**	**(99)**	**(385)**
CO2 Cost	-	-	6,802	6,545	11,795	11,366	11,831	11,396	11,924	11,478	-	(258)	(429)	(434)	(446)
CPVRR Through Year 2053 2020 $M	**38,336**	**38,240**	**45,297**	**44,940**	**47,237**	**46,833**	**50,416**	**49,883**	**57,892**	**57,060**	**(96)**	**(356)**	**(404)**	**(533)**	**(831)**

Negative means the additional solar units provide savings

EXHIBIT NO. LULAC-19

DOCKET NO: 20200176-EI

PARTY: LULAC

DESCRIPTION: CEC AFUDC WACC Calc Support from DEF's *CORRECTED* RESPONSE to LULAC's FIRST REQUEST for PRODUCTION of DOCUMENTS (NOS.1-8)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200176-EI EXHIBIT: 32
PARTY: LULAC
DESCRIPTION: LULAC-19 – CEC AFUDC WACC Calc Support from DEFs CORRECTED Response to LULACs 1 POD (1-8)

Capital Deployment Schedule/Cash Outflow - DERIVATION FOR CEC PROGRAM

ARCHER - w/o Land

Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades					$ 377,363	$ 168,933	$ 2,929,472	$ 132,480	$ 3,135,065	$ 7,891,716	$ 1,375,481	$ 8,947,981	$ 5,540,977	$ 3,308,205	$ 3,447,338	$ 3,473,384	$ 3,478,593	$ 13,312,904	$ 14,424,224	$ 14,154,848	$ 9,627,714	$ 2,744,265	$ 2,744,265	101,215,208
All Capital					$ 377,363	$ 168,933	$ 2,929,472	$ 132,480	$ 3,135,065	$ 7,891,716	$ 1,375,481	$ 8,947,981	$ 5,540,977	$ 3,308,205	$ 4,953,138	$ 4,979,184	$ 4,984,393	$ 14,818,704	$ 15,930,024	$ 14,154,848	$ 9,627,714	$ 2,744,265	$ 2,744,265	108,744,208
Monthly	0.00%	0.00%	0.00%	0.00%	0.35%	0.16%	2.69%	0.12%	2.88%	7.26%	1.26%	8.23%	5.10%	3.04%	4.55%	4.58%	4.58%	13.63%	14.65%	13.02%	8.85%	2.52%	2.52%	
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	0.35%	0.50%	3.20%	3.32%	6.20%	13.46%	14.72%	22.95%	28.05%	31.09%	35.64%	40.22%	44.81%	58.43%	73.08%	86.10%	94.95%	97.48%	100.00%	

CHARLIE CREEK

Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades					$ 4,044,230	$ 408,520	$ 692,726	$ 404,624	$ 408,166	$ 2,889,392	$ 2,727,495	$ 5,313,078	$ 5,112,242	$ 5,278,663	$ 5,460,718	$ 11,055,557	$ 14,746,709	$ 13,992,787	$ 12,332,809	$ 2,636,340	$ 2,507,203	$ 2,452,448	$ 2,452,448	94,916,156
W/ Network Upgrades					$ 4,044,230	$ 408,520	$ 692,726	$ 404,624	$ 408,166	$ 2,889,392	$ 2,727,495	$ 5,313,078	$ 5,112,242	$ 5,278,663	$ 9,103,442	$ 14,698,282	$ 18,389,433	$ 17,635,512	$ 15,975,534	$ 2,636,340	$ 2,507,203	$ 2,452,448	$ 2,452,448	113,129,779
Monthly	0.00%	0.00%	0.00%	0.00%	3.57%	0.36%	0.61%	0.36%	0.36%	2.55%	2.41%	4.70%	4.52%	4.67%	8.05%	12.99%	16.26%	15.59%	14.12%	2.33%	2.22%	2.17%	2.17%	
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	3.57%	3.94%	4.55%	4.91%	5.27%	7.82%	10.23%	14.93%	19.45%	24.11%	32.16%	45.15%	61.41%	77.00%	91.12%	93.45%	95.66%	97.83%	100.00%	

DUETEE - w/o Land

Cash Flow for AFUDC Calc	-22	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	COD	
W/O Network Upgrades					$ 562,060	$ 2,041,185	$ 4,646,442	$ 153,297	$ 5,520,248	$ 2,920,692	$ 401,860	$ 8,807,540	$ 5,334,528	$ 2,899,403	$ 11,855,414	$ 11,863,220	$ 11,988,496	$ 8,114,857	$ 5,966,721	$ 5,728,338	$ 6,096,739	$ 2,682,680	$ 2,630,636	100,214,356
W/ Network Upgrades					$ 562,060	$ 2,041,185	$ 4,646,442	$ 153,297	$ 5,520,248	$ 2,920,692	$ 672,060	$ 8,807,540	$ 5,334,528	$ 3,169,603	$ 12,125,614	$ 12,133,420	$ 12,393,796	$ 8,520,157	$ 6,372,021	$ 6,133,638	$ 6,096,739	$ 2,682,680	$ 2,630,636	102,916,356
Monthly	0.00%	0.00%	0.00%	0.00%	0.55%	1.98%	4.51%	0.15%	5.36%	2.84%	0.65%	8.56%	5.18%	3.08%	11.78%	11.79%	12.04%	8.28%	6.19%	5.96%	5.92%	2.61%	2.56%	
Cumulative Monthly	0.00%	0.00%	0.00%	0.00%	0.55%	2.53%	7.04%	7.19%	12.56%	15.39%	16.05%	24.61%	29.79%	32.87%	44.65%	56.44%	68.48%	76.76%	82.95%	88.91%	94.84%	97.44%	100.00%	

Monthly Spend as % of Total Capital (excluding Land)

																					COD	
	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0
Archer	0.00%	0.00%	0.00%	0.35%	0.16%	2.69%	0.12%	2.88%	7.26%	1.26%	8.23%	5.10%	3.04%	4.55%	4.58%	4.58%	13.63%	14.65%	13.02%	8.85%	2.52%	2.52%
Charlie Creek	0.00%	0.00%	0.00%	3.57%	0.36%	0.61%	0.36%	0.36%	2.55%	2.41%	4.70%	4.52%	4.67%	8.05%	12.99%	16.26%	15.59%	14.12%	2.33%	2.22%	2.17%	2.17%
Duette	0.00%	0.00%	0.00%	0.55%	1.98%	4.51%	0.15%	5.36%	2.84%	0.65%	8.56%	5.18%	3.08%	11.78%	11.79%	12.04%	8.28%	6.19%	5.96%	5.92%	2.61%	2.56%
Average	0.00%	0.00%	0.00%	1.49%	0.83%	2.61%	0.21%	2.87%	4.22%	1.44%	7.16%	4.93%	3.60%	8.13%	9.79%	10.96%	12.50%	11.65%	7.10%	5.66%	2.43%	2.42%

Cumulative Spend as % of Total Capital (excluding Land)

																					COD		
	-21	-20	-19	-18	-17	-16	-15	-14	-13	-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	
Archer	0.00%	0.00%	0.00%	0.35%	0.50%	3.20%	3.32%	6.20%	13.46%	14.72%	22.95%	28.05%	31.09%	35.64%	40.22%	44.81%	58.43%	73.08%	86.10%	94.95%	97.48%	100.00%	
Charlie Creek	0.00%	0.00%	0.00%	3.57%	3.94%	4.55%	4.91%	5.27%	7.82%	10.23%	14.93%	19.45%	24.11%	32.16%	45.15%	61.41%	77.00%	91.12%	93.45%	95.66%	97.83%	100.00%	
Duette	0.00%	0.00%	0.00%	0.55%	2.53%	7.04%	7.19%	12.56%	15.39%	16.05%	24.61%	29.79%	32.87%	44.65%	56.44%	68.48%	76.76%	82.95%	88.91%	94.84%	97.44%	100.00%	
Quarterly Cumulative Average	***0.00%***			***1.49%***			***5.14%***			***13.67%***			***29.36%***			***58.23%***			***89.49%***			***100.00%***	
6.07% 100.4923%																							
$ 93,000,000				1,385,083	774,938	2,424,514	194,818	2,668,352	3,921,226	1,341,939	6,659,690	4,587,288	3,344,280	7,558,966	9,101,849	10,193,219	11,623,321	10,838,206	6,605,121	5,268,058	2,262,403	2,246,727	
Cumulative	-	-	-	-	1,385,083	2,160,022	4,584,536	4,779,354	7,447,705	11,368,931	12,710,870	19,370,560	23,957,848	27,302,128	34,861,095	43,962,944	54,156,163	65,779,484	76,617,691	83,222,812	88,490,870	90,753,273	93,000,000
Ave Add	-	-	-	692,542	387,469	1,212,257	97,409	1,334,176	1,960,613	670,970	3,329,845	2,293,644	1,672,140	3,779,483	4,550,925	5,096,609	5,811,661	5,419,103	3,302,561	2,634,029	1,131,202	1,123,363	
AFUDC on Ave Add	-	-	-	695,950.98	389,376.50	1,218,224.98	97,888.29	1,340,743.77	1,970,264.65	674,272.80	3,346,237.25	2,304,935.22	1,680,371.61	3,798,088.96	4,573,328.17	5,121,699.19	5,840,270.49	5,445,780.52	3,318,818.49	2,646,995.86	1,136,770.42	1,128,893.61	
AFUDC on Full Monthly		-	-	-	2,091,279	5,362,899	14,412,871	29,190,842	62,554,217	131,336,870	265,346,428	542,054,297	1,093,703,190	2,197,839,885	4,417,912,334	8,871,315,811	17,801,693,941	35,708,572,212	71,609,295,918	143,581,085,245	287,876,950,234	577,174,486,570	
Ending including AFUDC	-	-	-	2,081,034	5,336,628	14,342,267	29,047,844	62,247,781	130,693,488	264,046,571	539,398,926	1,088,345,447	2,187,073,288	4,396,270,229	8,827,857,740	17,714,488,469	35,533,646,002	71,258,502,201	142,877,722,058	286,466,722,357	574,347,071,765	1,151,524,933,955	
																						1,151,431,933,955	

Generic Project

AFUDC Entity: DE Florida (NOTE 1)

	Total Annual Rate	Total Monthly Rate	
AFUDC Rate	6.07%	0.492283%	0.49%

Include Network Upgrades: y

	AFUDC
Yes	$ 2,316,758
No	$ 1,967,975

$ 100,000,000 Total CapEx

Month	Monthly Charges (source: PP download)	Half Current Month Expense	Cumulative Previous Month Expense	Cumulative Prior Month AFUDC	Total AFC Base	Current Month AFUDC	Capital Deployment % of Total CapEx	Capex	
	A	*B =A*1/2*	*C=All PM Expenses*	*D=All PM AFUDC*	*E=B+C+D*	*=E*G2*			
-18.00	$ 833,267	$ 416,633	$ -	$ -	$ 416,633	$ 2,051	1.49%	$ 1,489,337	
-17.00	$ 2,607,005	$ 1,303,502	$ 833,267	$ 2,051	$ 2,136,769	$ 10,519	0.83%	$ 833,267	
-16.00	$ 209,481	$ 104,741	$ 3,440,272	$ 12,570	$ 3,557,582	$ 17,513	2.61%	$ 2,607,005	
-15.00	$ 2,869,195	$ 1,434,598	$ 3,649,753	$ 30,083	$ 5,114,434	$ 25,178	0.21%	$ 209,481	
-14.00	$ 4,216,372	$ 2,108,186	$ 6,518,948	$ 55,261	$ 8,682,395	$ 42,742	2.87%	$ 2,869,195	
-13.00	$ 1,442,946	$ 721,473	$ 10,735,320	$ 98,003	$ 11,554,796	$ 56,882	4.22%	$ 4,216,372	
-12.00	$ 7,160,957	$ 3,580,478	$ 12,178,266	$ 154,885	$ 15,913,629	$ 78,340	1.44%	$ 1,442,946	
-11.00	$ 4,932,568	$ 2,466,284	$ 19,339,223	$ 233,225	$ 22,038,732	$ 108,493	7.16%	$ 7,160,957	
-10.00	$ 3,596,000	$ 1,798,000	$ 24,271,790	$ 341,718	$ 26,411,509	$ 130,019	4.93%	$ 4,932,568	
-9.00	$ 8,127,921	$ 4,063,960	$ 27,867,790	$ 471,738	$ 32,403,488	$ 159,517	3.60%	$ 3,596,000	
-8.00	$ 9,786,935	$ 4,893,467	$ 35,995,711	$ 631,255	$ 41,520,433	$ 204,398	8.13%	$ 8,127,921	
-7.00	$ 10,960,450	$ 5,480,225	$ 45,782,646	$ 835,653	$ 52,098,524	$ 256,472	9.79%	$ 9,786,935	
-6.00	$ 12,498,195	$ 6,249,097	$ 56,743,096	$ 1,092,125	$ 64,084,319	$ 315,476	10.96%	$ 10,960,450	
-5.00	$ 11,653,985	$ 5,826,993	$ 69,241,291	$ 1,407,602	$ 76,475,886	$ 376,478	12.50%	$ 12,498,195	
-4.00	$ 7,102,281	$ 3,551,140	$ 80,895,277	$ 1,784,080	$ 86,230,497	$ 424,498	11.65%	$ 11,653,985	
-3.00	$ 5,664,578	$ 2,832,289	$ 87,997,557	$ 2,208,578	$ 93,038,425	$ 458,013	7.10%	$ 7,102,281	
-2.00	$ 2,432,692	$ 1,216,346	$ 93,662,136	$ 2,666,591	$ 97,545,072	$ 480,198	5.66%	$ 5,664,578	
-1.00	$ 2,415,835	$ 1,207,918	$ 96,094,828	$ 3,146,789	$ 100,449,534	$ 494,496	2.43%	$ 2,432,692	Last Month of AFUDC
0.00	$ -	$ -	$ 98,510,663	$ 3,641,285	$ 102,151,948	$ -	2.42%	$ 2,415,835	In-Service Month
						$ 3,641,285			
							100.00%	$ 100,000,000	

***Total AFUDC* $ 3,641,285**   3.6413%

AFUDC stops accruing at Placed In Service

From March 2020 Standard Treasury Assumptions

	After-Tax	Pre-Tax	Notes
ROE	10.50%		
Debt		3.15%	Marginal Cost of Debt
% Equity	53%		
% Debt	47%		
Composite Tax Rate	25.35%		2022 forward

WACC/Discount Rate	After-Tax	Pre-Tax
Equity	5.57%	7.45%
Debt	1.11%	1.48%
Total	**6.67%**	**8.94%**