AUSLEY MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

October 16, 2017

**VIA: ELECTRONIC FILING**

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement, Docket No. 20170210-EI; Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 20160160-EI

Dear Ms. Stauffer:

Attached are Tampa Electric Company's responses to Staff's First Data Requests (Nos. 1-27). As indicated in the responses, confidential portions of the responsive documents will be made available at Staff's convenience in the office of Ausley McMullen.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

| | | |
|---|---|---|
| cc: | Bill McNulty | (w/attachment) |
| | R. Kelly/Charles Rehwinkel | (w/attachment) |
| | Jon C. Moyle, Jr. | (w/attachment) |
| | Robert Scheffel Wright | (w/attachment) |
| | Thomas Jernigan | (w/attachment) |
| | Mark Sundback | (w/attachment) |
| | Kenneth L. Wiseman | (w/attachment) |

## BEFORE THE

## FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| **In re: Petition by Tampa Electric Company for a Limited Proceeding to Approve 2017 Amended and Restated Stipulation and Settlement Agreement** | ) | **DOCKET NO. 20170210-EI** |
| **and** | | |
| **Petition by Tampa Electric Company for Approval of Energy Transaction Optimization Mechanism** | ) | **DOCKET NO. 20160160-EI** |
| | | **FILED: OCTOBER 16, 2017** |

## TAMPA ELECTRIC COMPANY'S

## ANSWERS TO FIRST DATA REQUEST (NOS. 1-27)

## OF

## FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files its Answers to Data Request (Nos. 1-27) propounded and served on October 11, 2017 by the Florida Public Service Commission Staff.

**1.** Please provide the assumptions used in calculating and the results of the three DSM cost-effectiveness models supporting the proposed program credits provided in Paragraph 3(e).

**A.** Tampa Electric used the results of the latest 2017 update to the cost-effectiveness model which included using 2016 actuals as directed by the Commission in responding to the Staff's 1st set of interrogatories, Interrogatory No. 1, which was filed with the Commission on July 31, 2017 within Docket No. 20170002-EG. The Rate Impact Measure Test ("RIM"), Total Resource Cost Test ("TRC") and Participant Cost Test ("PCT") cost-effectiveness test results for the three programs which would be affected by the Standby Generator Program credit increase and the Contracted Credit Value ("CCV") credit increase were updated with the proposed values and are included below. As an additional note, the credit that is paid to the participants of Tampa Electric's Commercial Demand Response Program is based on the Standby Generator credit. Below is a summary of the cost effectiveness results for each of the programs with the credit adjustments in the 2017 Agreement:

Standby Generator Program:

| | |
|---|---|
| RIM: | 1.93 |
| TRC: | 9.40 |
| PCT: | 1,317 |

Commercial Demand Response Program:

| | |
|---|---|
| RIM: | 1.40 |
| TRC: | 114.83 |
| PCT: | 2,067 |

CCV for the GSLM 2 & 3 Program:

| | |
|---|---|
| RIM: | 1.13 |
| TRC: | 31.14 |
| PCT: | 24,537 |

# INPUT DATA - PART 1
## PROGRAM TITLE: Standby Generator

PSC FORM CE 1.1
PAGE 1 OF 1
RUN DATE: October 14, 2017

**PROGRAM DEMAND SAVINGS & LINE LOSSES**

| | | | |
|---|---|---|---|
| I. | (1) CUSTOMER KW REDUCTION AT THE METER | 485.500 | KW /CUST |
| I. | (2) GENERATOR KW REDUCTION PER CUSTOMER | 540.417 | KW GEN/CUST |
| I. | (3) KW LINE LOSS PERCENTAGE | 7.00 | % |
| I. | (4) GENERATION KWH REDUCTION PER CUSTOMER | 51,213 | KWH/CUST/YR |
| I. | (5) KWH LINE LOSS PERCENTAGE | 5.20 | % |
| I. | (6) GROUP LINE LOSS MULTIPLIER | 1 | |
| I. | (7) CUSTOMER KWH PROGRAM INCREASE AT METER | 0 | KWH/CUST/YR |
| I. | (8)* CUSTOMER KWH REDUCTION AT METER | 48,550 | KWH/CUST/YR |

**ECONOMIC LIFE & K FACTORS**

| | | | |
|---|---|---|---|
| II. | (1) STUDY PERIOD FOR CONSERVATION PROGRAM | 25 | YEARS |
| II. | (2) GENERATOR ECONOMIC LIFE | 25 | YEARS |
| II. | (3) T & D ECONOMIC LIFE | 25 | YEARS |
| II. | (4) K FACTOR FOR GENERATION | 1.4181 | |
| II. | (5) K FACTOR FOR T & D | 1.4181 | |
| | (6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1) | 0 | |

**UTILITY & CUSTOMER COSTS**

| | | | |
|---|---|---|---|
| III. | (1) UTILITY NONRECURRING COST PER CUSTOMER | 6,304.00 | $/CUST |
| III. | (2) UTILITY RECURRING COST PER CUSTOMER | 386.00 | $/CUST/YR |
| III. | (3) UTILITY COST ESCALATION RATE | 2.40 | % |
| III. | (4) CUSTOMER EQUIPMENT COST | 0.00 | $/CUST |
| III. | (5) CUSTOMER EQUIPMENT ESCALATION RATE | 2.30 | % |
| III. | (6) CUSTOMER O & M COST | 4985.00 | $/CUST/YR |
| III. | (7) CUSTOMER O & M ESCALATION RATE | 2.30 | % |
| III. | (8)* CUSTOMER TAX CREDIT PER INSTALLATION | 0.00 | $/CUST |
| III. | (9)* CUSTOMER TAX CREDIT ESCALATION RATE | 0.00 | % |
| III. | (10)* INCREASED SUPPLY COSTS | 0.00 | $/CUST/YR |
| III. | (11)* SUPPLY COSTS ESCALATION RATE | 0.00 | % |
| III. | (12)* UTILITY DISCOUNT RATE | 0.06976 | |
| III. | (13)* UTILITY AFUDC RATE | 0.0646 | |
| III. | (14)* UTILITY NON RECURRING REBATE/INCENTIVE | 0.00 | $/CUST |
| III. | (15)* UTILITY RECURRING REBATE/INCENTIVE | 33,784.00 | $/CUST/YR |
| III. | (16)* UTILITY REBATE/INCENTIVE ESCAL RATE | 0.00 | % |

**AVOIDED GENERATOR, TRANS. & DIST COSTS**

| | | | |
|---|---|---|---|
| IV. | (1) BASE YEAR | 2017 | |
| IV. | (2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT | 2021 | |
| IV. | (3) IN-SERVICE YEAR FOR AVOIDED T & D | 2018 | |
| IV. | (4) BASE YEAR AVOIDED GENERATING UNIT COST | 682.22 | $/KW |
| IV. | (5) BASE YEAR AVOIDED TRANSMISSION COST | 37.16 | $/KW |
| IV. | (6) BASE YEAR DISTRIBUTION COST | 69.64 | $/KW |
| IV. | (7) GEN, TRAN, & DIST COST ESCALATION RATE | 2.40 | % |
| IV. | (8) GENERATOR FIXED O & M COST | 12.27 | $/KW/YR |
| IV. | (9) GENERATOR FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (10) TRANSMISSION FIXED O & M COST | 2.24 | $/KW/YR |
| IV. | (11) DISTRIBUTION FIXED O & M COST | 8.54 | $/KW/YR |
| IV. | (12) T&D FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (13) AVOIDED GEN UNIT VARIABLE O & M COSTS | 0.198 | CENTS/KWH |
| IV. | (14) GENERATOR VARIABLE O&M COST ESCALATION RATE | 2.40 | % |
| IV. | (15) GENERATOR CAPACITY FACTOR | 13.20 | % |
| IV. | (16) AVOIDED GENERATING UNIT FUEL COST | 3.95 | CENTS/KWH |
| IV. | (17) AVOIDED GEN UNIT FUEL ESCALATION RATE | 3.69 | % |
| IV. | (18)* AVOIDED PURCHASE CAPACITY COST PER KW | 0.00 | $/KW/YR |
| IV. | (19)* CAPACITY COST ESCALATION RATE | 0.00 | % |

**NON-FUEL ENERGY AND DEMAND CHARGES**

| | | | |
|---|---|---|---|
| V. | (1) NON-FUEL COST IN CUSTOMER BILL | 2.140 | CENTS/KWH |
| V. | (2) NON-FUEL ESCALATION RATE | 1.00 | % |
| V. | (3) CUSTOMER DEMAND CHARGE PER KW | 11.290 | $/KW/MO |
| V. | (4) DEMAND CHARGE ESCALATION RATE | 1.00 | % |
| V. | (5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL | 0.00 | |

| CALCULATED BENEFITS AND COSTS | |
|---|---|
| (1)* TRC TEST - BENEFIT/COST RATIO | **9.40** |
| (2)* PARTICIPANT NET BENEFITS (NPV) | **1,317** |
| (3)* RIM TEST - BENEFIT/COST RATIO | **1.93** |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20170210-EI**
**DOCKET NO. 20160160-EI**
**STAFF'S FIRST DATA REQUEST**
**FILED: OCTOBER 16, 2017**

TOTAL RESOURCE COST TESTS
PROGRAM: Standby Generator

PSC FORM CE 2.3
Page 1 of 1
October 14, 2017

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | INCREASED SUPPLY COSTS $(000) | UTILITY PROGRAM COSTS $(000) | PARTICIPANT PROGRAM COSTS $(000) | OTHER COSTS $(000) | TOTAL COSTS $(000) | AVOIDED GEN UNIT BENEFITS $(000) | AVOIDED T & D BENEFITS $(000) | PROGRAM FUEL SAVINGS $(000) | OTHER BENEFITS $(000) | TOTAL BENEFITS $(000) | NET BENEFITS $(000) | CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
| 2017 | 0 | 6 | 2 | 0 | 9 | 0 | 0 | 1 | 0 | 1 | (8) | (8) |
| 2018 | 0 | 7 | 8 | 0 | 15 | 0 | 22 | 2 | 0 | 24 | 9 | 0 |
| 2019 | 0 | 8 | 13 | 0 | 21 | 0 | 22 | 4 | 0 | 27 | 6 | 6 |
| 2020 | 0 | 8 | 19 | 0 | 27 | 0 | 23 | 6 | 0 | 29 | 2 | 7 |
| 2021 | 0 | 2 | 22 | 0 | 24 | 311 | 57 | 8 | 0 | 376 | 353 | 277 |
| 2022 | 0 | 2 | 22 | 0 | 24 | 304 | 56 | 8 | 0 | 368 | 344 | 522 |
| 2023 | 0 | 2 | 23 | 0 | 25 | 294 | 56 | 10 | 0 | 359 | 334 | 745 |
| 2024 | 0 | 2 | 23 | 0 | 25 | 284 | 55 | 6 | 0 | 345 | 320 | 944 |
| 2025 | 0 | 2 | 24 | 0 | 26 | 277 | 54 | 7 | 0 | 338 | 312 | 1,126 |
| 2026 | 0 | 2 | 24 | 0 | 26 | 271 | 54 | 11 | 0 | 335 | 309 | 1,295 |
| 2027 | 0 | 2 | 25 | 0 | 27 | 263 | 53 | 10 | 0 | 327 | 300 | 1,447 |
| 2028 | 0 | 2 | 26 | 0 | 28 | 258 | 53 | 11 | 0 | 322 | 295 | 1,588 |
| 2029 | 0 | 2 | 26 | 0 | 28 | 248 | 53 | 9 | 0 | 310 | 282 | 1,713 |
| 2030 | 0 | 2 | 27 | 0 | 29 | 243 | 52 | 11 | 0 | 306 | 277 | 1,828 |
| 2031 | 0 | 2 | 27 | 0 | 30 | 236 | 52 | 12 | 0 | 300 | 270 | 1,934 |
| 2032 | 0 | 2 | 28 | 0 | 30 | 232 | 52 | 12 | 0 | 295 | 265 | 2,030 |
| 2033 | 0 | 2 | 29 | 0 | 31 | 224 | 51 | 15 | 0 | 291 | 260 | 2,118 |
| 2034 | 0 | 2 | 29 | 0 | 32 | 219 | 51 | 16 | 0 | 286 | 254 | 2,199 |
| 2035 | 0 | 2 | 30 | 0 | 32 | 216 | 51 | 15 | 0 | 282 | 250 | 2,273 |
| 2036 | 0 | 2 | 31 | 0 | 33 | 218 | 51 | 13 | 0 | 282 | 249 | 2,342 |
| 2037 | 0 | 2 | 31 | 0 | 34 | 220 | 51 | 14 | 0 | 285 | 251 | 2,408 |
| 2038 | 0 | 3 | 32 | 0 | 35 | 221 | 51 | 14 | 0 | 286 | 251 | 2,469 |
| 2039 | 0 | 3 | 33 | 0 | 35 | 222 | 52 | 13 | 0 | 286 | 250 | 2,525 |
| 2040 | 0 | 3 | 34 | 0 | 36 | 226 | 52 | 15 | 0 | 294 | 257 | 2,580 |
| 2041 | 0 | 3 | 34 | 0 | 37 | 225 | 53 | 19 | 0 | 297 | 260 | 2,631 |
| NOMINAL | 0 | 75 | 623 | 0 | 698 | 5,210 | 1,178 | 262 | 0 | 6,650 | 5,952 | |
| NPV: | 0 | 45 | 269 | 0 | 313 | 2,304 | 534 | 106 | 0 | 2,945 | 2,631 | |

Discount Rate 0.06976 Benefit/Cost Ratio - [col (11)/col (6)]: 9.40

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Standby Generator

PSC FORM CE 2.4
Page 1 of 1
October 14, 2017

| (1) YEAR | (2) SAVINGS IN PARTICIPANTS BILL $(000) | (3) TAX CREDITS $(000) | (4) UTILITY REBATES $(000) | (5) OTHER BENEFITS $(000) | (6) TOTAL BENEFITS $(000) | (7) CUSTOMER EQUIPMENT COSTS $(000) | (8) CUSTOMER O & M COSTS $(000) | (9) OTHER COSTS $(000) | (10) TOTAL COSTS $(000) | (11) NET BENEFITS $(000) | (12) CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | 1 | 0 | 17 | 0 | 18 | 0 | 2 | 0 | 2 | 16 | 16 |
| 2018 | 4 | 0 | 51 | 0 | 55 | 0 | 8 | 0 | 8 | 47 | 60 |
| 2019 | 7 | 0 | 84 | 0 | 92 | 0 | 13 | 0 | 13 | 79 | 128 |
| 2020 | 10 | 0 | 118 | 0 | 129 | 0 | 19 | 0 | 19 | 110 | 218 |
| 2021 | 12 | 0 | 135 | 0 | 147 | 0 | 22 | 0 | 22 | 125 | 314 |
| 2022 | 12 | 0 | 135 | 0 | 147 | 0 | 22 | 0 | 22 | 125 | 403 |
| 2023 | 13 | 0 | 135 | 0 | 148 | 0 | 23 | 0 | 23 | 125 | 486 |
| 2024 | 13 | 0 | 135 | 0 | 148 | 0 | 23 | 0 | 23 | 125 | 564 |
| 2025 | 14 | 0 | 135 | 0 | 149 | 0 | 24 | 0 | 24 | 125 | 637 |
| 2026 | 14 | 0 | 135 | 0 | 149 | 0 | 24 | 0 | 24 | 125 | 705 |
| 2027 | 14 | 0 | 135 | 0 | 149 | 0 | 25 | 0 | 25 | 124 | 768 |
| 2028 | 15 | 0 | 135 | 0 | 150 | 0 | 26 | 0 | 26 | 124 | 828 |
| 2029 | 15 | 0 | 135 | 0 | 150 | 0 | 26 | 0 | 26 | 124 | 883 |
| 2030 | 16 | 0 | 135 | 0 | 151 | 0 | 27 | 0 | 27 | 124 | 934 |
| 2031 | 16 | 0 | 135 | 0 | 151 | 0 | 27 | 0 | 27 | 124 | 983 |
| 2032 | 16 | 0 | 135 | 0 | 152 | 0 | 28 | 0 | 28 | 124 | 1,028 |
| 2033 | 17 | 0 | 135 | 0 | 152 | 0 | 29 | 0 | 29 | 123 | 1,070 |
| 2034 | 17 | 0 | 135 | 0 | 153 | 0 | 29 | 0 | 29 | 123 | 1,109 |
| 2035 | 18 | 0 | 135 | 0 | 153 | 0 | 30 | 0 | 30 | 123 | 1,145 |
| 2036 | 18 | 0 | 135 | 0 | 153 | 0 | 31 | 0 | 31 | 122 | 1,179 |
| 2037 | 18 | 0 | 135 | 0 | 153 | 0 | 31 | 0 | 31 | 122 | 1,211 |
| 2038 | 18 | 0 | 135 | 0 | 153 | 0 | 32 | 0 | 32 | 121 | 1,240 |
| 2039 | 19 | 0 | 135 | 0 | 154 | 0 | 33 | 0 | 33 | 121 | 1,267 |
| 2040 | 19 | 0 | 135 | 0 | 154 | 0 | 34 | 0 | 34 | 120 | 1,293 |
| 2041 | 19 | 0 | 135 | 0 | 154 | 0 | 34 | 0 | 34 | 120 | 1,317 |
| NOMINAL | 356 | 0 | 3,108 | 0 | 3,464 | 0 | 623 | 0 | 623 | 2,841 | |
| NPV: | 152 | 0 | 1,433 | 0 | 1,585 | 0 | 269 | 0 | 269 | 1,317 | |
| In service year of gen unit: | | | 2021 | | 5.9030066 | | | | | | |

RATE IMPACT TEST
PROGRAM: Standby Generator

PSC FORM CE 2.5
Page 1 of 1
October 14, 2017

| (1) YEAR | (2) INCREASED SUPPLY COSTS $(000) | (3) UTILITY PROGRAM COSTS $(000) | (4) INCENTIVES $(000) | (5) REVENUE LOSSES $(000) | (6) OTHER COSTS $(000) | (7) TOTAL COSTS $(000) | (8) AVOIDED GEN UNIT UNIT & FUEL BENEFITS $(000) | (9) AVOIDED T & D BENEFITS $(000) | (10) REVENUE GAINS $(000) | (11) OTHER BENEFITS $(000) | (12) TOTAL BENEFITS $(000) | (13) NET BENEFITS TO ALL CUSTOMERS $(000) | (14) CUMULATIVE DISCOUNTED NET BENEFIT $(000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | 0 | 6 | 17 | 1 | 0 | 24 | 1 | 0 | 0 | 0 | 1 | (23) | (23) |
| 2018 | 0 | 7 | 51 | 2 | 0 | 59 | 2 | 22 | 0 | 0 | 24 | (35) | (56) |
| 2019 | 0 | 8 | 84 | 3 | 0 | 95 | 4 | 22 | 0 | 0 | 27 | (68) | (116) |
| 2020 | 0 | 8 | 118 | 4 | 0 | 130 | 6 | 23 | 0 | 0 | 29 | (101) | (199) |
| 2021 | 0 | 2 | 135 | 4 | 0 | 141 | 319 | 57 | 0 | 0 | 376 | 235 | (19) |
| 2022 | 0 | 2 | 135 | 4 | 0 | 141 | 312 | 56 | 0 | 0 | 368 | 227 | 143 |
| 2023 | 0 | 2 | 135 | 4 | 0 | 141 | 303 | 56 | 0 | 0 | 359 | 217 | 288 |
| 2024 | 0 | 2 | 135 | 4 | 0 | 141 | 290 | 55 | 0 | 0 | 345 | 204 | 415 |
| 2025 | 0 | 2 | 135 | 5 | 0 | 142 | 283 | 54 | 0 | 0 | 338 | 196 | 529 |
| 2026 | 0 | 2 | 135 | 5 | 0 | 142 | 281 | 54 | 0 | 0 | 335 | 194 | 635 |
| 2027 | 0 | 2 | 135 | 5 | 0 | 142 | 273 | 53 | 0 | 0 | 327 | 185 | 729 |
| 2028 | 0 | 2 | 135 | 5 | 0 | 142 | 269 | 53 | 0 | 0 | 322 | 180 | 815 |
| 2029 | 0 | 2 | 135 | 5 | 0 | 142 | 257 | 53 | 0 | 0 | 310 | 168 | 890 |
| 2030 | 0 | 2 | 135 | 5 | 0 | 142 | 254 | 52 | 0 | 0 | 306 | 164 | 958 |
| 2031 | 0 | 2 | 135 | 5 | 0 | 142 | 248 | 52 | 0 | 0 | 300 | 158 | 1020 |
| 2032 | 0 | 2 | 135 | 5 | 0 | 142 | 244 | 52 | 0 | 0 | 295 | 153 | 1075 |
| 2033 | 0 | 2 | 135 | 5 | 0 | 142 | 239 | 51 | 0 | 0 | 291 | 148 | 1126 |
| 2034 | 0 | 2 | 135 | 5 | 0 | 142 | 235 | 51 | 0 | 0 | 286 | 144 | 1171 |
| 2035 | 0 | 2 | 135 | 5 | 0 | 142 | 231 | 51 | 0 | 0 | 282 | 140 | 1213 |
| 2036 | 0 | 2 | 135 | 5 | 0 | 143 | 231 | 51 | 0 | 0 | 282 | 140 | 1252 |
| 2037 | 0 | 2 | 135 | 5 | 0 | 143 | 234 | 51 | 0 | 0 | 285 | 143 | 1289 |
| 2038 | 0 | 3 | 135 | 5 | 0 | 143 | 235 | 51 | 0 | 0 | 286 | 143 | 1323 |
| 2039 | 0 | 3 | 135 | 5 | 0 | 143 | 234 | 52 | 0 | 0 | 286 | 143 | 1356 |
| 2040 | 0 | 3 | 135 | 5 | 0 | 143 | 241 | 52 | 0 | 0 | 294 | 151 | 1388 |
| 2041 | 0 | 3 | 135 | 5 | 0 | 143 | 244 | 53 | 0 | 0 | 297 | 154 | 1418 |
| NOMINAL | 0 | 75 | 3,108 | 109 | 0 | 3,292 | 5,472 | 1,178 | 0 | 0 | 6,650 | 3,358 | |
| NPV: | 0 | 45 | 1,433 | 49 | 0 | 1,527 | 2,411 | 534 | 0 | 0 | 2,945 | 1,418 | |

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.93

# INPUT DATA - PART 1
## PROGRAM TITLE: Commercial Demand Response


RUN DATE: October 14, 2017

**PROGRAM DEMAND SAVINGS & LINE LOSSES**

| | | | |
|---|---|---|---|
| I. | (1) CUSTOMER KW REDUCTION AT THE METER | 470.590 | KW /CUST |
| I. | (2) GENERATOR KW REDUCTION PER CUSTOMER | 523.821 | KW GEN/CUST |
| I. | (3) KW LINE LOSS PERCENTAGE | 7.00 | % |
| I. | (4) GENERATION KWH REDUCTION PER CUSTOMER | 37,230 | KWH/CUST/YR |
| I. | (5) KWH LINE LOSS PERCENTAGE | 5.20 | % |
| I. | (6) GROUP LINE LOSS MULTIPLIER | 1 | |
| I. | (7) CUSTOMER KWH PROGRAM INCREASE AT METER | 0 | KWH/CUST/YR |
| I. | (8)* CUSTOMER KWH REDUCTION AT METER | 35,294 | KWH/CUST/YR |

**ECONOMIC LIFE & K FACTORS**

| | | | |
|---|---|---|---|
| II. | (1) STUDY PERIOD FOR CONSERVATION PROGRAM | 25 | YEARS |
| II. | (2) GENERATOR ECONOMIC LIFE | 25 | YEARS |
| II. | (3) T & D ECONOMIC LIFE | 25 | YEARS |
| II. | (4) K FACTOR FOR GENERATION | 1.4181 | |
| II. | (5) K FACTOR FOR T & D | 1.4181 | |
| | (6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1) | 0 | |

**UTILITY & CUSTOMER COSTS**

| | | | |
|---|---|---|---|
| III. | (1) UTILITY NONRECURRING COST PER CUSTOMER | 860.00 | $/CUST |
| III. | (2) UTILITY RECURRING COST PER CUSTOMER | 393.00 | $/CUST/YR |
| III. | (3) UTILITY COST ESCALATION RATE | 2.40 | % |
| III. | (4) CUSTOMER EQUIPMENT COST | 0.00 | $/CUST |
| III. | (5) CUSTOMER EQUIPMENT ESCALATION RATE | 2.30 | % |
| III. | (6) CUSTOMER O & M COST | 0.00 | $/CUST/YR |
| III. | (7) CUSTOMER O & M ESCALATION RATE | 2.30 | % |
| III. | (8)* CUSTOMER TAX CREDIT PER INSTALLATION | 0.00 | $/CUST |
| III. | (9)* CUSTOMER TAX CREDIT ESCALATION RATE | 0.00 | % |
| III. | (10)* INCREASED SUPPLY COSTS | 0.00 | $/CUST/YR |
| III. | (11)* SUPPLY COSTS ESCALATION RATE | 0.00 | % |
| III. | (12)* UTILITY DISCOUNT RATE | 0.06976 | |
| III. | (13)* UTILITY AFUDC RATE | 0.0646 | |
| III. | (14)* UTILITY NON RECURRING REBATE/INCENTIVE | 0.00 | $/CUST |
| III. | (15)* UTILITY RECURRING REBATE/INCENTIVE | 46,117.70 | $/CUST/YR |
| III. | (16)* UTILITY REBATE/INCENTIVE ESCAL RATE | 0.00 | % |

**AVOIDED GENERATOR, TRANS. & DIST COSTS**

| | | | |
|---|---|---|---|
| IV. | (1) BASE YEAR | 2017 | |
| IV. | (2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT | 2021 | |
| IV. | (3) IN-SERVICE YEAR FOR AVOIDED T & D | 2018 | |
| IV. | (4) BASE YEAR AVOIDED GENERATING UNIT COST | 682.22 | $/KW |
| IV. | (5) BASE YEAR AVOIDED TRANSMISSION COST | 37.16 | $/KW |
| IV. | (6) BASE YEAR DISTRIBUTION COST | 69.64 | $/KW |
| IV. | (7) GEN, TRAN, & DIST COST ESCALATION RATE | 2.40 | % |
| IV. | (8) GENERATOR FIXED O & M COST | 12.27 | $/KW/YR |
| IV. | (9) GENERATOR FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (10) TRANSMISSION FIXED O & M COST | 2.24 | $/KW/YR |
| IV. | (11) DISTRIBUTION FIXED O & M COST | 8.54 | $/KW/YR |
| IV. | (12) T&D FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (13) AVOIDED GEN UNIT VARIABLE O & M COSTS | 0.198 | CENTS/KWH |
| IV. | (14) GENERATOR VARIABLE O&M COST ESCALATION RATE | 2.40 | % |
| IV. | (15) GENERATOR CAPACITY FACTOR | 13.20 | % |
| IV. | (16) AVOIDED GENERATING UNIT FUEL COST | 3.95 | CENTS/KWH |
| IV. | (17) AVOIDED GEN UNIT FUEL ESCALATION RATE | 3.69 | % |
| IV. | (18)* AVOIDED PURCHASE CAPACITY COST PER KW | 0.00 | $/KW/YR |
| IV. | (19)* CAPACITY COST ESCALATION RATE | 0.00 | % |

**NON-FUEL ENERGY AND DEMAND CHARGES**

| | | | |
|---|---|---|---|
| V. | (1) NON-FUEL COST IN CUSTOMER BILL | 2.140 | CENTS/KWH |
| V. | (2) NON-FUEL ESCALATION RATE | 1.00 | % |
| V. | (3) CUSTOMER DEMAND CHARGE PER KW | 11.290 | $/KW/MO |
| V. | (4) DEMAND CHARGE ESCALATION RATE | 1.00 | % |
| V. | (5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL | 0.00 | |

| CALCULATED BENEFITS AND COSTS | |
|---|---|
| (1)* TRC TEST - BENEFIT/COST RATIO | **114.83** |
| (2)* PARTICIPANT NET BENEFITS (NPV) | **2,067** |
| (3)* RIM TEST - BENEFIT/COST RATIO | **1.40** |

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

PSC FORM CE 2.3
Page 1 of 1
October 14, 2017

TOTAL RESOURCE COST TESTS
PROGRAM: Commercial Demand Response

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | INCREASED SUPPLY COSTS $(000) | UTILITY PROGRAM COSTS $(000) | PARTICIPANT PROGRAM COSTS $(000) | OTHER COSTS $(000) | TOTAL COSTS $(000) | AVOIDED GEN UNIT BENEFITS $(000) | AVOIDED T & D BENEFITS $(000) | PROGRAM FUEL SAVINGS $(000) | OTHER BENEFITS $(000) | TOTAL BENEFITS $(000) | NET BENEFITS $(000) | CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
| 2017 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | (1) | (1) |
| 2018 | 0 | 1 | 0 | 0 | 1 | 0 | 21 | 2 | 0 | 23 | 21 | 19 |
| 2019 | 0 | 2 | 0 | 0 | 2 | 0 | 22 | 3 | 0 | 25 | 23 | 39 |
| 2020 | 0 | 2 | 0 | 0 | 2 | 0 | 22 | 4 | 0 | 27 | 24 | 59 |
| 2021 | 0 | 2 | 0 | 0 | 2 | 301 | 55 | 6 | 0 | 363 | 361 | 335 |
| 2022 | 0 | 2 | 0 | 0 | 2 | 295 | 55 | 6 | 0 | 355 | 353 | 587 |
| 2023 | 0 | 2 | 0 | 0 | 2 | 284 | 54 | 7 | 0 | 345 | 343 | 816 |
| 2024 | 0 | 2 | 0 | 0 | 2 | 275 | 53 | 5 | 0 | 333 | 331 | 1,022 |
| 2025 | 0 | 2 | 0 | 0 | 2 | 268 | 53 | 5 | 0 | 326 | 324 | 1,211 |
| 2026 | 0 | 2 | 0 | 0 | 2 | 262 | 52 | 8 | 0 | 322 | 320 | 1,385 |
| 2027 | 0 | 2 | 0 | 0 | 2 | 255 | 52 | 7 | 0 | 314 | 312 | 1,544 |
| 2028 | 0 | 2 | 0 | 0 | 2 | 250 | 51 | 8 | 0 | 310 | 307 | 1,691 |
| 2029 | 0 | 2 | 0 | 0 | 2 | 241 | 51 | 7 | 0 | 298 | 296 | 1,823 |
| 2030 | 0 | 2 | 0 | 0 | 2 | 235 | 51 | 8 | 0 | 294 | 292 | 1,944 |
| 2031 | 0 | 2 | 0 | 0 | 2 | 229 | 50 | 9 | 0 | 288 | 286 | 2,055 |
| 2032 | 0 | 2 | 0 | 0 | 2 | 224 | 50 | 9 | 0 | 283 | 281 | 2,158 |
| 2033 | 0 | 2 | 0 | 0 | 2 | 217 | 50 | 11 | 0 | 278 | 276 | 2,251 |
| 2034 | 0 | 2 | 0 | 0 | 2 | 212 | 50 | 12 | 0 | 273 | 271 | 2,337 |
| 2035 | 0 | 2 | 0 | 0 | 2 | 210 | 49 | 11 | 0 | 270 | 267 | 2,417 |
| 2036 | 0 | 2 | 0 | 0 | 2 | 211 | 49 | 10 | 0 | 270 | 268 | 2,491 |
| 2037 | 0 | 3 | 0 | 0 | 3 | 213 | 49 | 10 | 0 | 273 | 270 | 2,561 |
| 2038 | 0 | 3 | 0 | 0 | 3 | 214 | 50 | 10 | 0 | 274 | 271 | 2,627 |
| 2039 | 0 | 3 | 0 | 0 | 3 | 215 | 50 | 9 | 0 | 274 | 271 | 2,689 |
| 2040 | 0 | 3 | 0 | 0 | 3 | 219 | 51 | 11 | 0 | 281 | 278 | 2,748 |
| 2041 | 0 | 3 | 0 | 0 | 3 | 218 | 51 | 14 | 0 | 283 | 280 | 2,803 |
| NOMINAL | 0 | 53 | 0 | 0 | 53 | 5,049 | 1,142 | 190 | 0 | 6,381 | 6,328 | |
| NPV: | 0 | 25 | 0 | 0 | 25 | 2,233 | 517 | 77 | 0 | 2,828 | 2,803 | |

Discount Rate 0.06976 Benefit/Cost Ratio - [col (11)/col (6)]: 114.83

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Commercial Demand Response

PSC FORM CE 2.4
Page 1 of 1
October 14, 2017

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | SAVINGS IN PARTICIPANTS BILL $(000) | TAX CREDITS $(000) | UTILITY REBATES $(000) | OTHER BENEFITS $(000) | TOTAL BENEFITS $(000) | CUSTOMER EQUIPMENT COSTS $(000) | CUSTOMER O & M COSTS $(000) | OTHER COSTS $(000) | TOTAL COSTS $(000) | NET BENEFITS $(000) | CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
| 2017 | 1 | 0 | 23 | 0 | 24 | 0 | 0 | 0 | 0 | 24 | 24 |
| 2018 | 3 | 0 | 69 | 0 | 72 | 0 | 0 | 0 | 0 | 72 | 91 |
| 2019 | 5 | 0 | 115 | 0 | 120 | 0 | 0 | 0 | 0 | 120 | 197 |
| 2020 | 8 | 0 | 161 | 0 | 169 | 0 | 0 | 0 | 0 | 169 | 335 |
| 2021 | 9 | 0 | 184 | 0 | 193 | 0 | 0 | 0 | 0 | 193 | 482 |
| 2022 | 9 | 0 | 184 | 0 | 193 | 0 | 0 | 0 | 0 | 193 | 620 |
| 2023 | 9 | 0 | 184 | 0 | 194 | 0 | 0 | 0 | 0 | 194 | 749 |
| 2024 | 10 | 0 | 184 | 0 | 194 | 0 | 0 | 0 | 0 | 194 | 871 |
| 2025 | 10 | 0 | 184 | 0 | 194 | 0 | 0 | 0 | 0 | 194 | 984 |
| 2026 | 10 | 0 | 184 | 0 | 195 | 0 | 0 | 0 | 0 | 195 | 1,090 |
| 2027 | 10 | 0 | 184 | 0 | 195 | 0 | 0 | 0 | 0 | 195 | 1,189 |
| 2028 | 11 | 0 | 184 | 0 | 195 | 0 | 0 | 0 | 0 | 195 | 1,282 |
| 2029 | 11 | 0 | 184 | 0 | 196 | 0 | 0 | 0 | 0 | 196 | 1,369 |
| 2030 | 11 | 0 | 184 | 0 | 196 | 0 | 0 | 0 | 0 | 196 | 1,451 |
| 2031 | 12 | 0 | 184 | 0 | 196 | 0 | 0 | 0 | 0 | 196 | 1,527 |
| 2032 | 12 | 0 | 184 | 0 | 196 | 0 | 0 | 0 | 0 | 196 | 1,598 |
| 2033 | 12 | 0 | 184 | 0 | 197 | 0 | 0 | 0 | 0 | 197 | 1,665 |
| 2034 | 13 | 0 | 184 | 0 | 197 | 0 | 0 | 0 | 0 | 197 | 1,728 |
| 2035 | 13 | 0 | 184 | 0 | 197 | 0 | 0 | 0 | 0 | 197 | 1,787 |
| 2036 | 13 | 0 | 184 | 0 | 197 | 0 | 0 | 0 | 0 | 197 | 1,841 |
| 2037 | 13 | 0 | 184 | 0 | 197 | 0 | 0 | 0 | 0 | 197 | 1,893 |
| 2038 | 13 | 0 | 184 | 0 | 198 | 0 | 0 | 0 | 0 | 198 | 1,941 |
| 2039 | 14 | 0 | 184 | 0 | 198 | 0 | 0 | 0 | 0 | 198 | 1,986 |
| 2040 | 14 | 0 | 184 | 0 | 198 | 0 | 0 | 0 | 0 | 198 | 2,028 |
| 2041 | 14 | 0 | 184 | 0 | 199 | 0 | 0 | 0 | 0 | 199 | 2,067 |
| NOMINAL | 258 | 0 | 4,243 | 0 | 4,501 | 0 | 0 | 0 | 0 | 4,501 | |
| NPV: | 111 | 0 | 1,956 | 0 | 2,067 | 0 | 0 | 0 | 0 | 2,067 | |
| In service year of gen unit: | | | 2021 | | #DIV/0! | | | | | | |

RATE IMPACT TEST
PROGRAM: Commercial Demand Response

PSC FORM CE 2.5
Page 1 of 1
October 14, 2017

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | INCREASED SUPPLY COSTS | UTILITY PROGRAM COSTS | INCENTIVES | REVENUE LOSSES | OTHER COSTS | TOTAL COSTS | AVOIDED GEN UNIT UNIT & FUEL BENEFITS | AVOIDED T & D BENEFITS | REVENUE GAINS | OTHER BENEFITS | TOTAL BENEFITS | NET BENEFITS TO ALL CUSTOMERS | CUMULATIVE DISCOUNTED NET BENEFIT |
| YEAR | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) |
| 2017 | 0 | 1 | 23 | 0 | 0 | 24 | 0 | 0 | 0 | 0 | 0 | (24) | (24) |
| 2018 | 0 | 1 | 69 | 1 | 0 | 72 | 2 | 21 | 0 | 0 | 23 | (49) | (70) |
| 2019 | 0 | 2 | 115 | 2 | 0 | 119 | 3 | 22 | 0 | 0 | 25 | (94) | (152) |
| 2020 | 0 | 2 | 161 | 3 | 0 | 167 | 4 | 22 | 0 | 0 | 27 | (140) | (267) |
| 2021 | 0 | 2 | 184 | 3 | 0 | 189 | 308 | 55 | 0 | 0 | 363 | 173 | (134) |
| 2022 | 0 | 2 | 184 | 3 | 0 | 189 | 300 | 55 | 0 | 0 | 355 | 166 | (16) |
| 2023 | 0 | 2 | 184 | 3 | 0 | 189 | 291 | 54 | 0 | 0 | 345 | 156 | 88 |
| 2024 | 0 | 2 | 184 | 3 | 0 | 190 | 280 | 53 | 0 | 0 | 333 | 143 | 177 |
| 2025 | 0 | 2 | 184 | 3 | 0 | 190 | 273 | 53 | 0 | 0 | 326 | 136 | 256 |
| 2026 | 0 | 2 | 184 | 3 | 0 | 190 | 270 | 52 | 0 | 0 | 322 | 133 | 329 |
| 2027 | 0 | 2 | 184 | 3 | 0 | 190 | 262 | 52 | 0 | 0 | 314 | 124 | 392 |
| 2028 | 0 | 2 | 184 | 3 | 0 | 190 | 258 | 51 | 0 | 0 | 310 | 120 | 449 |
| 2029 | 0 | 2 | 184 | 3 | 0 | 190 | 247 | 51 | 0 | 0 | 298 | 108 | 497 |
| 2030 | 0 | 2 | 184 | 3 | 0 | 190 | 243 | 51 | 0 | 0 | 294 | 104 | 540 |
| 2031 | 0 | 2 | 184 | 3 | 0 | 190 | 237 | 50 | 0 | 0 | 288 | 98 | 578 |
| 2032 | 0 | 2 | 184 | 4 | 0 | 190 | 233 | 50 | 0 | 0 | 283 | 93 | 612 |
| 2033 | 0 | 2 | 184 | 4 | 0 | 190 | 228 | 50 | 0 | 0 | 278 | 88 | 642 |
| 2034 | 0 | 2 | 184 | 4 | 0 | 190 | 224 | 50 | 0 | 0 | 273 | 83 | 668 |
| 2035 | 0 | 2 | 184 | 4 | 0 | 190 | 220 | 49 | 0 | 0 | 270 | 79 | 692 |
| 2036 | 0 | 2 | 184 | 4 | 0 | 191 | 221 | 49 | 0 | 0 | 270 | 80 | 714 |
| 2037 | 0 | 3 | 184 | 4 | 0 | 191 | 224 | 49 | 0 | 0 | 273 | 82 | 735 |
| 2038 | 0 | 3 | 184 | 4 | 0 | 191 | 224 | 50 | 0 | 0 | 274 | 83 | 755 |
| 2039 | 0 | 3 | 184 | 4 | 0 | 191 | 224 | 50 | 0 | 0 | 274 | 83 | 774 |
| 2040 | 0 | 3 | 184 | 4 | 0 | 191 | 230 | 51 | 0 | 0 | 281 | 90 | 793 |
| 2041 | 0 | 3 | 184 | 4 | 0 | 191 | 232 | 51 | 0 | 0 | 283 | 92 | 812 |
| NOMINAL | 0 | 53 | 4,243 | 79 | 0 | 4,375 | 5,239 | 1,142 | 0 | 0 | 6,381 | 2,006 | |
| NPV: | 0 | 25 | 1,956 | 35 | 0 | 2,016 | 2,311 | 517 | 0 | 0 | 2,828 | 812 | |

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.40

PSC FORM CE 1.1
PAGE 1 OF 1
RUN DATE: October 14, 2017

## INPUT DATA - PART 1
## PROGRAM TITLE: Contracted Credit Value Calculation

**PROGRAM DEMAND SAVINGS & LINE LOSSES**

| | | | |
|---|---|---|---|
| I. | (1) CUSTOMER KW REDUCTION AT THE METER | 4,264.710 | KW /CUST |
| I. | (2) GENERATOR KW REDUCTION PER CUSTOMER | 4,550.705 | KW GEN/CUST |
| I. | (3) KW LINE LOSS PERCENTAGE | 7.00 | % |
| I. | (4) GENERATION KWH REDUCTION PER CUSTOMER | 1,049,268 | KWH/CUST/YR |
| I. | (5) KWH LINE LOSS PERCENTAGE | 5.20 | % |
| I. | (6) GROUP LINE LOSS MULTIPLIER | 1 | |
| I. | (7) CUSTOMER KWH PROGRAM INCREASE AT METER | 0 | KWH/CUST/YR |
| I. | (8)* CUSTOMER KWH REDUCTION AT METER | 994,706 | KWH/CUST/YR |

**ECONOMIC LIFE & K FACTORS**

| | | | |
|---|---|---|---|
| II. | (1) STUDY PERIOD FOR CONSERVATION PROGRAM | 25 | YEARS |
| II. | (2) GENERATOR ECONOMIC LIFE | 25 | YEARS |
| II. | (3) T & D ECONOMIC LIFE | 25 | YEARS |
| II. | (4) K FACTOR FOR GENERATION | 1.4181 | |
| II. | (5) K FACTOR FOR T & D | 1.4181 | |
| | (6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1) | 0 | |

**UTILITY & CUSTOMER COSTS**

| | | | |
|---|---|---|---|
| III. | (1) UTILITY NONRECURRING COST PER CUSTOMER | 122,946.00 | $/CUST |
| III. | (2) UTILITY RECURRING COST PER CUSTOMER | 4,104.00 | $/CUST/YR |
| III. | (3) UTILITY COST ESCALATION RATE | 2.40 | % |
| III. | (4) CUSTOMER EQUIPMENT COST | 42,000.00 | $/CUST |
| III. | (5) CUSTOMER EQUIPMENT ESCALATION RATE | 2.30 | % |
| III. | (6) CUSTOMER O & M COST | 0.00 | $/CUST/YR |
| III. | (7) CUSTOMER O & M ESCALATION RATE | 2.30 | % |
| III. | (8)* CUSTOMER TAX CREDIT PER INSTALLATION | 0.00 | $/CUST |
| III. | (9)* CUSTOMER TAX CREDIT ESCALATION RATE | 0.00 | % |
| III. | (10)* INCREASED SUPPLY COSTS | 0.00 | $/CUST/YR |
| III. | (11)* SUPPLY COSTS ESCALATION RATE | 0.00 | % |
| III. | (12)* UTILITY DISCOUNT RATE | 0.06976 | |
| III. | (13)* UTILITY AFUDC RATE | 0.0646 | |
| III. | (14)* UTILITY NON RECURRING REBATE/INCENTIVE | 0.00 | $/CUST |
| III. | (15)* UTILITY RECURRING REBATE/INCENTIVE | 508,623.60 | $/CUST/YR |
| III. | (16)* UTILITY REBATE/INCENTIVE ESCAL RATE | 0.00 | % |

**AVOIDED GENERATOR, TRANS. & DIST COSTS**

| | | | |
|---|---|---|---|
| IV. | (1) BASE YEAR | 2017 | |
| IV. | (2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT | 2021 | |
| IV. | (3) IN-SERVICE YEAR FOR AVOIDED T & D | 2018 | |
| IV. | (4) BASE YEAR AVOIDED GENERATING UNIT COST | 682.22 | $/KW |
| IV. | (5) BASE YEAR AVOIDED TRANSMISSION COST | 37.16 | $/KW |
| IV. | (6) BASE YEAR DISTRIBUTION COST | 69.64 | $/KW |
| IV. | (7) GEN, TRAN, & DIST COST ESCALATION RATE | 2.40 | % |
| IV. | (8) GENERATOR FIXED O & M COST | 12.27 | $/KW/YR |
| IV. | (9) GENERATOR FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (10) TRANSMISSION FIXED O & M COST | 2.24 | $/KW/YR |
| IV. | (11) DISTRIBUTION FIXED O & M COST | 8.54 | $/KW/YR |
| IV. | (12) T&D FIXED O&M ESCALATION RATE | 2.40 | % |
| IV. | (13) AVOIDED GEN UNIT VARIABLE O & M COSTS | 0.198 | CENTS/KWH |
| IV. | (14) GENERATOR VARIABLE O&M COST ESCALATION RATE | 2.40 | % |
| IV. | (15) GENERATOR CAPACITY FACTOR | 13.20 | % |
| IV. | (16) AVOIDED GENERATING UNIT FUEL COST | 3.95 | CENTS/KWH |
| IV. | (17) AVOIDED GEN UNIT FUEL ESCALATION RATE | 3.69 | % |
| IV. | (18)* AVOIDED PURCHASE CAPACITY COST PER KW | 0.00 | $/KW/YR |
| IV. | (19)* CAPACITY COST ESCALATION RATE | 0.00 | % |

**NON-FUEL ENERGY AND DEMAND CHARGES**

| | | | |
|---|---|---|---|
| V. | (1) NON-FUEL COST IN CUSTOMER BILL | 2.140 | CENTS/KWH |
| V. | (2) NON-FUEL ESCALATION RATE | 1.00 | % |
| V. | (3) CUSTOMER DEMAND CHARGE PER KW | 11.290 | $/KW/MO |
| V. | (4) DEMAND CHARGE ESCALATION RATE | 1.00 | % |
| V. | (5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL | 0.00 | |

| CALCULATED BENEFITS AND COSTS | |
|---|---|
| (1)* TRC TEST - BENEFIT/COST RATIO | **31.14** |
| (2)* PARTICIPANT NET BENEFITS (NPV) | **24,537** |
| (3)* RIM TEST - BENEFIT/COST RATIO | **1.13** |

TOTAL RESOURCE COST TESTS
PROGRAM: Contracted Credit Value Calculation

PSC FORM CE 2.3
Page 1 of 1
October 14, 2017

| (1) YEAR | (2) INCREASED SUPPLY COSTS $(000) | (3) UTILITY PROGRAM COSTS $(000) | (4) PARTICIPANT PROGRAM COSTS $(000) | (5) OTHER COSTS $(000) | (6) TOTAL COSTS $(000) | (7) AVOIDED GEN UNIT BENEFITS $(000) | (8) AVOIDED T & D BENEFITS $(000) | (9) PROGRAM FUEL SAVINGS $(000) | (10) OTHER BENEFITS $(000) | (11) TOTAL BENEFITS $(000) | (12) NET BENEFITS $(000) | (13) CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | 0 | 125 | 42 | 0 | 167 | 0 | 0 | 13 | 0 | 13 | (154) | (154) |
| 2018 | 0 | 132 | 43 | 0 | 175 | 0 | 191 | 43 | 0 | 234 | 59 | (99) |
| 2019 | 0 | 140 | 44 | 0 | 184 | 0 | 196 | 85 | 0 | 280 | 97 | (14) |
| 2020 | 0 | 147 | 45 | 0 | 192 | 0 | 200 | 119 | 0 | 319 | 127 | 90 |
| 2021 | 0 | 18 | 0 | 0 | 18 | 2,619 | 493 | 171 | 0 | 3,283 | 3,265 | 2,583 |
| 2022 | 0 | 18 | 0 | 0 | 18 | 2,560 | 488 | 162 | 0 | 3,210 | 3,191 | 4,860 |
| 2023 | 0 | 19 | 0 | 0 | 19 | 2,471 | 482 | 196 | 0 | 3,149 | 3,130 | 6,949 |
| 2024 | 0 | 19 | 0 | 0 | 19 | 2,388 | 476 | 131 | 0 | 2,996 | 2,977 | 8,806 |
| 2025 | 0 | 20 | 0 | 0 | 20 | 2,328 | 472 | 137 | 0 | 2,937 | 2,917 | 10,507 |
| 2026 | 0 | 20 | 0 | 0 | 20 | 2,278 | 468 | 219 | 0 | 2,965 | 2,944 | 12,111 |
| 2027 | 0 | 21 | 0 | 0 | 21 | 2,214 | 464 | 209 | 0 | 2,887 | 2,866 | 13,571 |
| 2028 | 0 | 21 | 0 | 0 | 21 | 2,170 | 461 | 233 | 0 | 2,864 | 2,843 | 14,925 |
| 2029 | 0 | 22 | 0 | 0 | 22 | 2,090 | 458 | 185 | 0 | 2,733 | 2,711 | 16,132 |
| 2030 | 0 | 22 | 0 | 0 | 22 | 2,044 | 455 | 223 | 0 | 2,722 | 2,699 | 17,256 |
| 2031 | 0 | 23 | 0 | 0 | 23 | 1,986 | 452 | 244 | 0 | 2,682 | 2,659 | 18,290 |
| 2032 | 0 | 23 | 0 | 0 | 23 | 1,950 | 449 | 245 | 0 | 2,645 | 2,622 | 19,244 |
| 2033 | 0 | 24 | 0 | 0 | 24 | 1,889 | 447 | 304 | 0 | 2,640 | 2,616 | 20,133 |
| 2034 | 0 | 25 | 0 | 0 | 25 | 1,841 | 445 | 332 | 0 | 2,618 | 2,593 | 20,957 |
| 2035 | 0 | 25 | 0 | 0 | 25 | 1,822 | 442 | 301 | 0 | 2,565 | 2,540 | 21,712 |
| 2036 | 0 | 26 | 0 | 0 | 26 | 1,836 | 441 | 272 | 0 | 2,549 | 2,524 | 22,413 |
| 2037 | 0 | 26 | 0 | 0 | 26 | 1,851 | 443 | 295 | 0 | 2,589 | 2,563 | 23,078 |
| 2038 | 0 | 27 | 0 | 0 | 27 | 1,859 | 446 | 283 | 0 | 2,588 | 2,561 | 23,699 |
| 2039 | 0 | 28 | 0 | 0 | 28 | 1,866 | 449 | 257 | 0 | 2,573 | 2,546 | 24,277 |
| 2040 | 0 | 28 | 0 | 0 | 28 | 1,903 | 453 | 317 | 0 | 2,673 | 2,644 | 24,837 |
| 2041 | 0 | 29 | 0 | 0 | 29 | 1,898 | 456 | 390 | 0 | 2,744 | 2,715 | 25,376 |
| NOMINAL | 0 | 1,030 | 174 | 0 | 1,204 | 43,867 | 10,226 | 5,366 | 0 | 59,459 | 58,256 | |
| NPV: | 0 | 685 | 157 | 0 | 842 | 19,403 | 4,633 | 2,181 | 0 | 26,218 | 25,376 | |

Discount Rate 0.06976

Benefit/Cost Ratio - [col (11)/col (6)]: 31.14

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Contracted Credit Value Calculation

PSC FORM CE 2.4
Page 1 of 1
October 14, 2017

| (1) YEAR | (2) SAVINGS IN PARTICIPANTS BILL $(000) | (3) TAX CREDITS $(000) | (4) UTILITY REBATES $(000) | (5) OTHER BENEFITS $(000) | (6) TOTAL BENEFITS $(000) | (7) CUSTOMER EQUIPMENT COSTS $(000) | (8) CUSTOMER O & M COSTS $(000) | (9) OTHER COSTS $(000) | (10) TOTAL COSTS $(000) | (11) NET BENEFITS $(000) | (12) CUMULATIVE DISCOUNTED NET BENEFITS $(000) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | 28 | 0 | 254 | 0 | 282 | 42 | 0 | 0 | 42 | 240 | 240 |
| 2018 | 81 | 0 | 763 | 0 | 844 | 43 | 0 | 0 | 43 | 801 | 989 |
| 2019 | 146 | 0 | 1,272 | 0 | 1,418 | 44 | 0 | 0 | 44 | 1,374 | 2,189 |
| 2020 | 211 | 0 | 1,780 | 0 | 1,992 | 45 | 0 | 0 | 45 | 1,947 | 3,780 |
| 2021 | 246 | 0 | 2,034 | 0 | 2,280 | 0 | 0 | 0 | 0 | 2,280 | 5,521 |
| 2022 | 252 | 0 | 2,034 | 0 | 2,286 | 0 | 0 | 0 | 0 | 2,286 | 7,153 |
| 2023 | 261 | 0 | 2,034 | 0 | 2,296 | 0 | 0 | 0 | 0 | 2,296 | 8,684 |
| 2024 | 271 | 0 | 2,034 | 0 | 2,306 | 0 | 0 | 0 | 0 | 2,306 | 10,122 |
| 2025 | 278 | 0 | 2,034 | 0 | 2,312 | 0 | 0 | 0 | 0 | 2,312 | 11,471 |
| 2026 | 284 | 0 | 2,034 | 0 | 2,318 | 0 | 0 | 0 | 0 | 2,318 | 12,734 |
| 2027 | 293 | 0 | 2,034 | 0 | 2,328 | 0 | 0 | 0 | 0 | 2,328 | 13,920 |
| 2028 | 300 | 0 | 2,034 | 0 | 2,334 | 0 | 0 | 0 | 0 | 2,334 | 15,032 |
| 2029 | 313 | 0 | 2,034 | 0 | 2,348 | 0 | 0 | 0 | 0 | 2,348 | 16,077 |
| 2030 | 321 | 0 | 2,034 | 0 | 2,355 | 0 | 0 | 0 | 0 | 2,355 | 17,057 |
| 2031 | 331 | 0 | 2,034 | 0 | 2,365 | 0 | 0 | 0 | 0 | 2,365 | 17,977 |
| 2032 | 337 | 0 | 2,034 | 0 | 2,371 | 0 | 0 | 0 | 0 | 2,371 | 18,840 |
| 2033 | 348 | 0 | 2,034 | 0 | 2,383 | 0 | 0 | 0 | 0 | 2,383 | 19,650 |
| 2034 | 358 | 0 | 2,034 | 0 | 2,392 | 0 | 0 | 0 | 0 | 2,392 | 20,410 |
| 2035 | 362 | 0 | 2,034 | 0 | 2,397 | 0 | 0 | 0 | 0 | 2,397 | 21,122 |
| 2036 | 362 | 0 | 2,034 | 0 | 2,397 | 0 | 0 | 0 | 0 | 2,397 | 21,787 |
| 2037 | 366 | 0 | 2,034 | 0 | 2,401 | 0 | 0 | 0 | 0 | 2,401 | 22,411 |
| 2038 | 373 | 0 | 2,034 | 0 | 2,408 | 0 | 0 | 0 | 0 | 2,408 | 22,995 |
| 2039 | 381 | 0 | 2,034 | 0 | 2,416 | 0 | 0 | 0 | 0 | 2,416 | 23,543 |
| 2040 | 384 | 0 | 2,034 | 0 | 2,419 | 0 | 0 | 0 | 0 | 2,419 | 24,056 |
| 2041 | 396 | 0 | 2,034 | 0 | 2,430 | 0 | 0 | 0 | 0 | 2,430 | 24,537 |
| NOMINAL | 7,284 | 0 | 46,793 | 0 | 54,077 | 174 | 0 | 0 | 174 | 53,903 | |
| NPV: | 3,120 | 0 | 21,575 | 0 | 24,695 | 157 | 0 | 0 | 157 | 24,537 | |
| In service year of gen unit: | | | 2021 | | 156.98922 | | | | | | |

RATE IMPACT TEST
PROGRAM: Contracted Credit Value Calculation

PSC FORM CE 2.5
Page 1 of 1
October 14, 2017

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | INCREASED SUPPLY COSTS | UTILITY PROGRAM COSTS | INCENTIVES | REVENUE LOSSES | OTHER COSTS | TOTAL COSTS | AVOIDED GEN UNIT UNIT & FUEL BENEFITS | AVOIDED T & D BENEFITS | REVENUE GAINS | OTHER BENEFITS | TOTAL BENEFITS | NET BENEFITS TO ALL CUSTOMERS | CUMULATIVE DISCOUNTED NET BENEFIT |
| YEAR | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) | $(000) |
| 2017 | 0 | 125 | 254 | 11 | 0 | 390 | 13 | 0 | 0 | 0 | 13 | (377) | (377) |
| 2018 | 0 | 132 | 763 | 32 | 0 | 927 | 43 | 191 | 0 | 0 | 234 | (693) | (1025) |
| 2019 | 0 | 140 | 1,272 | 54 | 0 | 1,466 | 85 | 196 | 0 | 0 | 280 | (1,185) | (2060) |
| 2020 | 0 | 147 | 1,780 | 77 | 0 | 2,004 | 119 | 200 | 0 | 0 | 319 | (1,685) | (3437) |
| 2021 | 0 | 18 | 2,034 | 89 | 0 | 2,141 | 2,790 | 493 | 0 | 0 | 3,283 | 1,142 | (2565) |
| 2022 | 0 | 18 | 2,034 | 89 | 0 | 2,142 | 2,722 | 488 | 0 | 0 | 3,210 | 1,067 | (1803) |
| 2023 | 0 | 19 | 2,034 | 90 | 0 | 2,144 | 2,667 | 482 | 0 | 0 | 3,149 | 1,005 | (1132) |
| 2024 | 0 | 19 | 2,034 | 91 | 0 | 2,145 | 2,520 | 476 | 0 | 0 | 2,996 | 851 | (602) |
| 2025 | 0 | 20 | 2,034 | 92 | 0 | 2,147 | 2,466 | 472 | 0 | 0 | 2,937 | 791 | (141) |
| 2026 | 0 | 20 | 2,034 | 93 | 0 | 2,148 | 2,497 | 468 | 0 | 0 | 2,965 | 817 | 304 |
| 2027 | 0 | 21 | 2,034 | 94 | 0 | 2,149 | 2,423 | 464 | 0 | 0 | 2,887 | 737 | 680 |
| 2028 | 0 | 21 | 2,034 | 95 | 0 | 2,151 | 2,403 | 461 | 0 | 0 | 2,864 | 713 | 1020 |
| 2029 | 0 | 22 | 2,034 | 96 | 0 | 2,152 | 2,275 | 458 | 0 | 0 | 2,733 | 580 | 1278 |
| 2030 | 0 | 22 | 2,034 | 97 | 0 | 2,154 | 2,267 | 455 | 0 | 0 | 2,722 | 568 | 1515 |
| 2031 | 0 | 23 | 2,034 | 98 | 0 | 2,155 | 2,230 | 452 | 0 | 0 | 2,682 | 527 | 1720 |
| 2032 | 0 | 23 | 2,034 | 99 | 0 | 2,157 | 2,196 | 449 | 0 | 0 | 2,645 | 488 | 1897 |
| 2033 | 0 | 24 | 2,034 | 100 | 0 | 2,158 | 2,193 | 447 | 0 | 0 | 2,640 | 482 | 2061 |
| 2034 | 0 | 25 | 2,034 | 101 | 0 | 2,160 | 2,173 | 445 | 0 | 0 | 2,618 | 458 | 2207 |
| 2035 | 0 | 25 | 2,034 | 102 | 0 | 2,162 | 2,123 | 442 | 0 | 0 | 2,565 | 403 | 2326 |
| 2036 | 0 | 26 | 2,034 | 103 | 0 | 2,163 | 2,108 | 441 | 0 | 0 | 2,549 | 386 | 2434 |
| 2037 | 0 | 26 | 2,034 | 104 | 0 | 2,165 | 2,146 | 443 | 0 | 0 | 2,589 | 425 | 2544 |
| 2038 | 0 | 27 | 2,034 | 105 | 0 | 2,166 | 2,142 | 446 | 0 | 0 | 2,588 | 422 | 2646 |
| 2039 | 0 | 28 | 2,034 | 106 | 0 | 2,168 | 2,124 | 449 | 0 | 0 | 2,573 | 405 | 2738 |
| 2040 | 0 | 28 | 2,034 | 107 | 0 | 2,170 | 2,220 | 453 | 0 | 0 | 2,673 | 503 | 2845 |
| 2041 | 0 | 29 | 2,034 | 108 | 0 | 2,172 | 2,288 | 456 | 0 | 0 | 2,744 | 572 | 2958 |
| NOMINAL | 0 | 1,030 | 46,793 | 2,233 | 0 | 50,056 | 49,233 | 10,226 | 0 | 0 | 59,459 | 9,403 | |
| NPV: | 0 | 685 | 21,575 | 1,000 | 0 | 23,259 | 21,585 | 4,633 | 0 | 0 | 26,218 | 2,958 | |

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.13

**2.** If Paragraph 3(e) is approved, what impact will this have on the 2019 factors requested by the company in Docket No. 20180002-EG? Please explain.

**A.** The proposed credit adjustments, if approved, will cause an incremental increase in the company's Energy Conservation Cost Recovery ("ECCR") Clause of approximately $1,766,450 in 2018. This was calculated by comparing the proposed credit adjustments being added to the current Standby Generator and Commercial Demand Response credits and the proposed CCV credit for 2018. Tampa Electric projects the annual incremental increase in credits to equate to an approximate increase in the ECCR Clause of 10.4 cents per 1,000 kWh for the 2019 factors that will be requested by the company in Docket No. 20180002-EG.

**3.** If the proposed Settlement is approved, does the company anticipate any additional impacts to the Energy Conservation Cost Recovery clause, including any material impacts to the clause factors? Please explain.

**A.** Tampa Electric does not anticipate any additional impacts to the ECCR Clause if the 2017 Agreement is approved.

**4.** Paragraph 3(e) states:

*The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.*

Does this preclude the Commission from considering the cost-effectiveness of these programs and/or changing the credits in a future DSM proceeding? Please explain.

**A.** This term was negotiated by the Parties to the 2017 Agreement, and is part of a comprehensive and interdependent settlement that fairly reflects a compromise of the competing viewpoints among the parties, reduces the risks and costs of pursuing litigation before the FPSC, avoids the substantial time and costs associated with a traditional base rate proceeding and provides certainty and predictability for customers, the Consumer Parties and the company for a period of four years through 2021 (hereinafter, "Negotiated Term").

Pursuant to Paragraph 3(e), the SoBRA increases remain in effect after the expiration of the Term, until changed, if at all by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding, and the same applies to the credits. Nothing in the 2017 Agreement precludes the Commission from considering the cost-effectiveness of these two programs at any time; however, if the commission approves the 2017 Agreement, the quoted language in Paragraph 3(e) would limit the Commission's ability to change the level of the credits for these two programs until the same time that all other base rates are changed, i.e. in a future Commission-approved settlement or through final Commission decisions in a general base rate proceeding for Tampa Electric.

**5.** Has TECO begun the process of soliciting bids/proposals for the various SoBRA Tranches? If yes, please provide a detailed narrative explaining the process to date, including deadlines for entities to submit their bids/proposals to TECO. Also, please provide a copy of TECO's request for bids/proposals.

**A.** Yes. The company used a competitive process to review qualifications and experience of, identify and select full service solar developers. Three full service solar developers were selected to enter into contract negotiations to provide project development and engineering, procurement and construction services for the 600 MW of Tampa Electric solar projects.

Tampa Electric employed a Request for Information ("RFI") process to collect information from the bidders with respect to their qualifications, capabilities and experience as full service solar developers. On April 12, 2017, the RFI was provided to more than 60 companies that Tampa Electric had met and/or discussed the development and construction of utility scale solar projects. On April 21, 2017, Tampa Electric received more than 30 responses from solar developers and/or solar engineering procurement and construction ("EPC") companies. The company used the information from the RFI responses to select a shortlist of four full service solar developers.

The shortlisted developers were asked to provide pricing for 7 PV solar projects that ranged in size from 20-74.5 $MW_{AC}$. The pricing information was broken out for engineering and permitting, equipment, balance of system, installation and interconnection. The projects were based on sites that Tampa Electric has purchased or for which the company has site control. During the pricing phase of the selection process one developer withdrew. The pricing evaluation was conducted during May 2017 and included interviews with each developer.

In early June 2017, Tampa Electric awarded the three-shortlisted full-service solar developers individual projects for sites that are planned for Tampa Electric's 600 MW of PV solar.

Tampa Electric and developers executed limited notice to proceed agreements in June 2017 for each site in the first two tranches to enable engineering and permitting to be initiated.

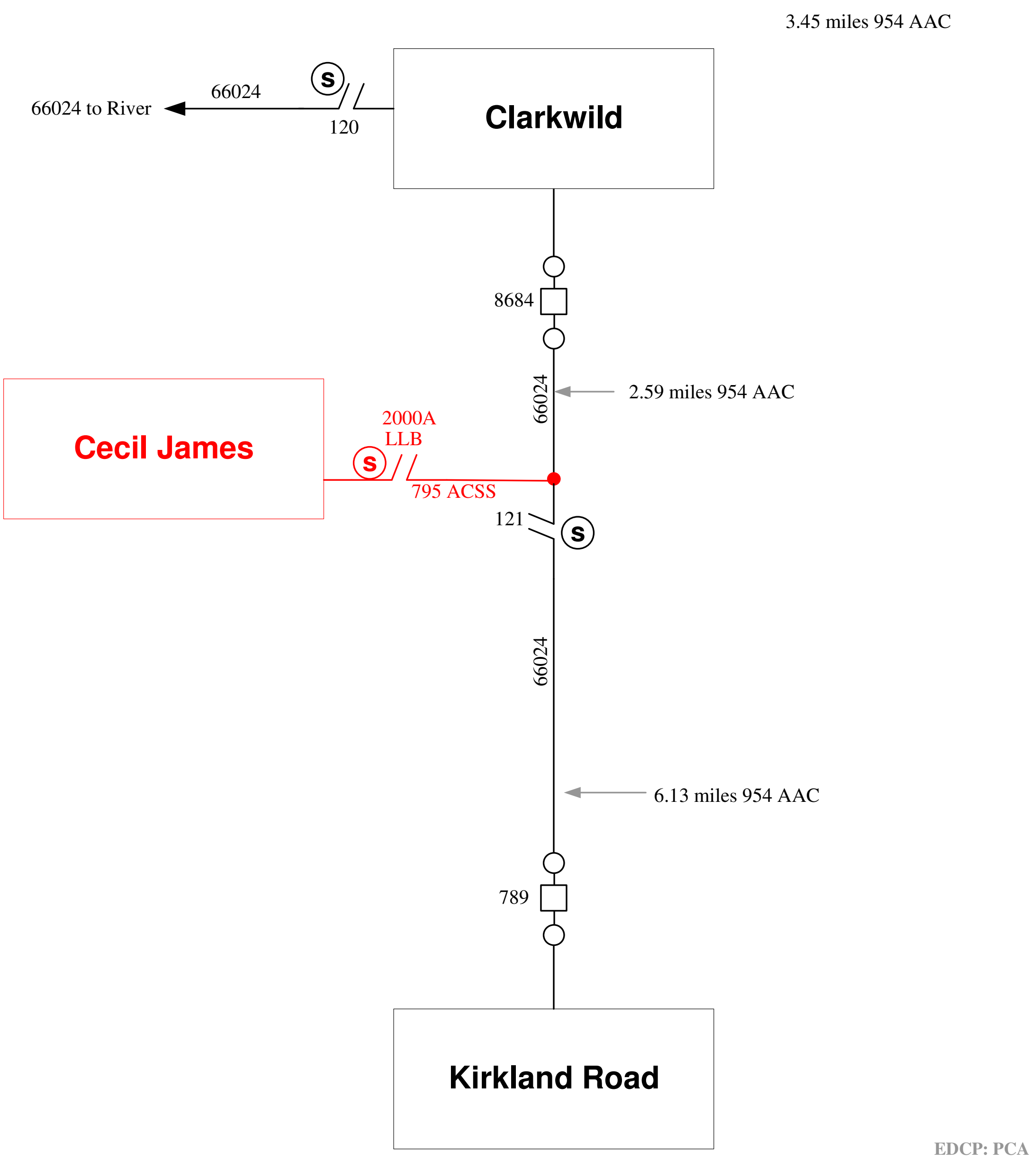
Tampa Electric expects to complete and execute the turn-key agreement for the first tranche projects in the month of October 2017.

Tampa Electric plans to negotiate and execute turn-key agreements for the remaining project tranches before the end of 2017.

The RFI used by the company is included as an attachment to this response.

| | |
|---|---|
| **TITLE: Cecil James Solar Facility** | **2018** |
| **DESCR:** Tap circuit 66024 to connect to new Meter Station for Cecil James Solar Facility.<br>Install a 2000A LLB supervisory transmission line switch on Circuit 66024 north of new tap. | **IN SVC BY:**<br>**Jun**<br>**See Construction Schedule** |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

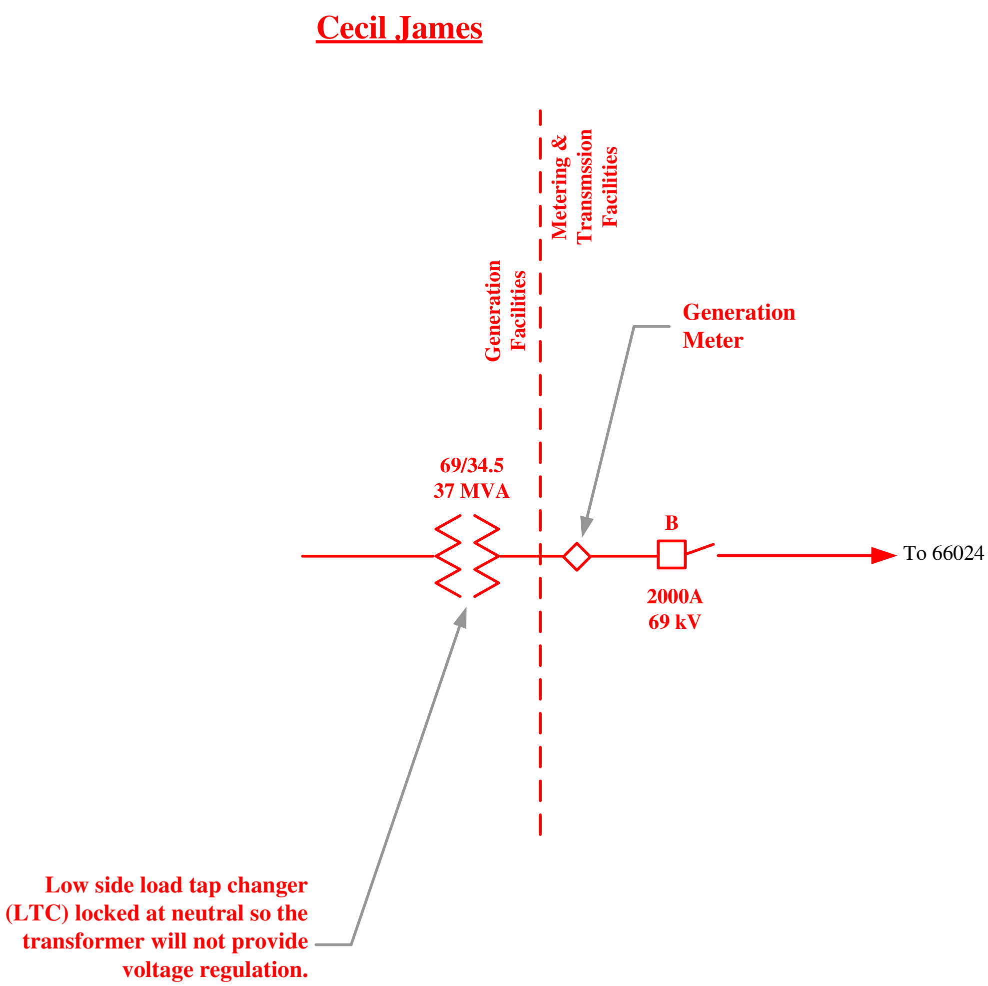



EDCP: PCA

| | | | | |
|---|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | | ESTIMATE #: **1960.000** | **T** |
| | SUB #: | ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | | |

| | |
|---|---|
| **TITLE:** Cecil James Solar Facility | **2018** |
| **DESCR:** Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station. | **IN SVC BY:** **Jun** See Construction Schedule |
| **NOTES:** Cecil James Solar Facility will be tapped off 69 kV circuit 66024 and is expected to have an output of 33MW | |

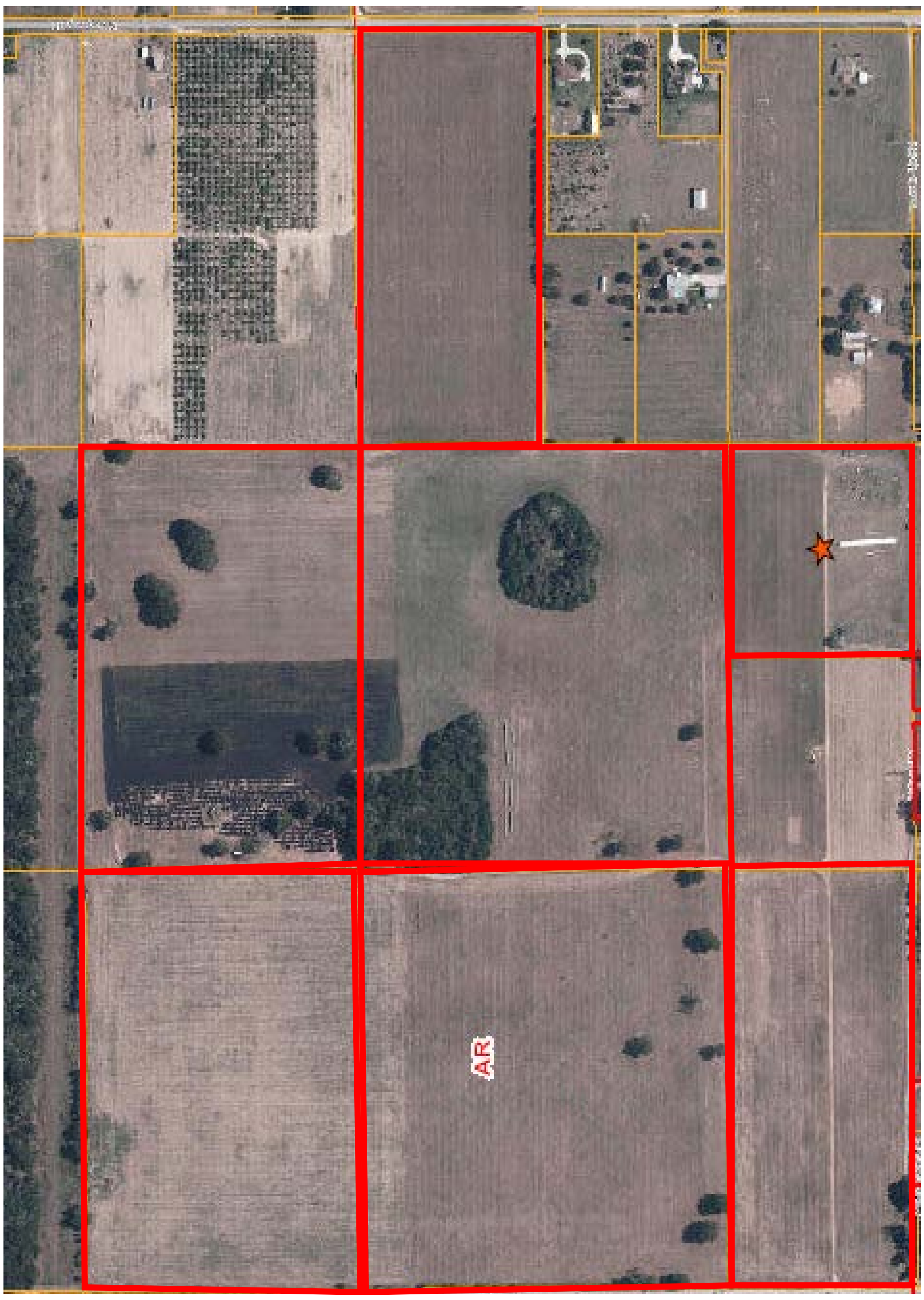
Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**



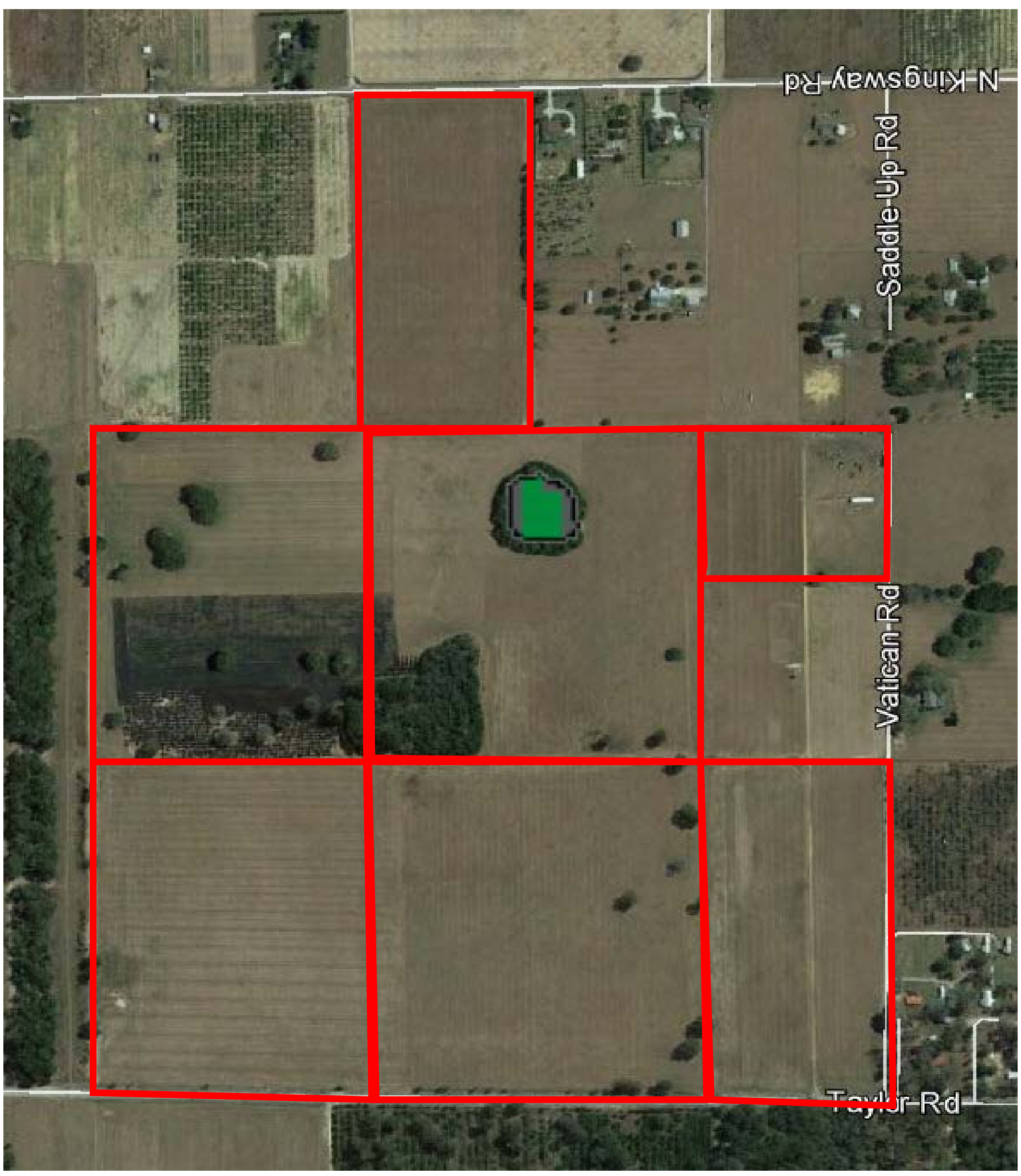

EDCP: PCA

| | | | |
|---|---|---|---|
| IMPROVEMENT: | | ESTIMATE #: 1960.000 | S |
| SUB #: | ISSUE DATE: 04/18/2017 | REVISION DATE: | |
| E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | | |

Cecile B. James, Nancy Burnett and John W. James Jr.
199± Acres on Saddle Up Road
Existing Land Use - AR



Cecile B. James, Nancy Burnett and John W. James Jr.
199± Acres on Saddle Up Road
Potential Wetlands Area




NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

# DUE DILIGENCE REPORT

## CECIL B. JAMES PROPERTY
## SADDLE UP ROAD
## THONOTOSASSA, HILLSBOROUGH COUNTY, FLORIDA

*Prepared for:*

## SLA 75, LLC

*Prepared by:*

ECT Environmental Consulting & Technology, Inc.
1408 N. Westshore Boulevard, Suite 115
Tampa, Florida 33607
(813) 289-9338
www.ectinc.com

ECT No. 170265-0100

May 24, 2017

## TABLE OF CONTENTS

# DUE DILIGENCE

## LAND USE PLANNING

***Jurisdiction***

The Cecil B. James property (also referred to as the subject property or the property) is located in the Thonotosassa area of unincorporated Hillsborough County. The subject property is located in the Thonotosassa Community Plan, according to the Livable Communities Element of the Hillsborough County Comprehensive Plan. There do not appear to be any goals or policies of the Community Plan that would potentially impact the construction and operation of a solar farm.

***Hillsborough County Future Land Use Map (FLUM) Designation***

The Future Land Use Map (FLUM) land use designation of the subject property is Agricultural/Rural-1/5 (AR-1/5) and Residential-1 (RES-1). The AR-1/5 land use designation allows up to one dwelling unit per five acres. Typical uses are identified as farms, ranches, residential uses, neighborhood commercial uses, office uses, and industrial uses related to agricultural uses. The specific intent of the land use category is to designate areas of agricultural uses or other rural uses. Solar farms are not listed as a use in the AR-1/5 land use designation. The RES-1 land use designation allows up to one dwelling unit per acre. Typical uses are identified as farms, ranches, residential uses, neighborhood commercial uses, office uses, and multi-purpose uses. The specific intent of the land use category is to designate areas for rural residential use compatible with short term agricultural uses. Solar farms are not listed as a use in the RES-1 land use designation.

Adjacent land use categories are:

- AR-1/5 to the north, east, and south; and
- Residential-2 to the west.

The subject property is not located within the Urban Service Area and it is not shown as overlain by major wetlands or significant wildlife habitat.

The Comprehensive Plan has a series of maps within the Future Land Use, Transportation, and Conservation Elements, among others. A review of the applicable maps indicates the following:

- The property does not appear to be located within the 100-year floodplain.
- There are no historic structures or archaeological resources shown onsite.
- Kingsway Road is identified as a scenic corridor.
- Kingsway Road, along the eastern property boundary, is currently identified as a local road and as a 2-lane road on the 2025 Corridor Preservation Plan.
- An extension of Joe Ebert Road (to the west) connecting to McIntosh Road (to the east) is shown transecting the subject property as a 2-lane road on the 2025 Corridor Preservation Plan.
- The subject property is not shown as a natural recharge area.
- The subject property is not located in a wellfield resource protection area.
- The subject property is not identified as environmentally sensitive relative to wetlands, natural systems, strategic habitat, and surface water protection areas.

Development of the subject property is potentially impacted by the planned 2-lane roadway extension across the southern portion. A typical section for a 2-lane, undivided, rural road depicts a minimum 96-foot right-of-way, according to the Hillsborough County Transportation Technical Manual (2015). Adjacent development is restricted to up to two dwelling units per acre to the west and one unit per five acres to the north, east, and south.

***Hillsborough County Zoning District***

The subject property is located in the Agricultural Rural (AR) zoning district. The purpose of the AR zoning district is to protect viable long-term agricultural lands from urban and suburban encroachment by encouraging agricultural and related uses. Solar energy production is listed as a conditional use.

The adjacent zoning district in all directions is AR. A Planned Development (PD 05-0960) is identified north of the transmission line corridor.

***Existing Land Uses***

The subject property is currently undeveloped and used as hay production.

The adjacent land uses are:

- Undeveloped transmission line corridor to the north followed by undeveloped land or land in agricultural use;
- Undeveloped land and land in agricultural use to the west;
- Residences and agricultural uses to the south; and
- Residences and agricultural uses to the east.

***Discussion***

While the Future Land Use Element of the Comprehensive Plan addresses electrical power generation facilities, the Land Development Code excludes solar generation less than 75 megawatts from the definition of electrical power generation facilities. The only land use category that lists solar farms as a typical use is Energy Industrial Park. The proposed use (solar energy generation) is not compatible with this land use category because at least two renewable energy technologies are required.

The proposed solar energy use can be accommodated within the existing land use category of AR-1/5 since the AR zoning district allows this use as a conditional use. A FLUM amendment and a rezoning are not required.

The Hillsborough County Land Development Code allows solar energy production facility as a conditional use. The conditional use standards for this use are:

**Sec. 6.11.125. - Solar Energy Production Facility**

A. In agricultural zoning districts, the host parcel shall be a minimum of five acres in size.

B. In agricultural zoning districts, a minimum setback of 50 feet shall be required from all boundaries of the site. This setback shall apply to all solar panels and other above-ground structures excluding transmission line poles.

1. In the M (Manufacturing) district, solar panels and other above-ground structures excluding transmission line poles shall conform with principal structure setback requirements.

C. In agricultural zoning districts, the solar panels shall be ground mounted and have a maximum height of 15 feet as measured when the panels are tilted to the design degree that creates the greatest overall height. All other structures shall conform with principal structure height requirements of this Code.

1. In the M district, all structures including solar panels shall conform with principal structure height requirements of this Code.

D. Ground-mounted facilities shall be enclosed with a security fence with a minimum height of six feet to discourage unauthorized entry. The fence location and maximum height shall comply with the requirements of this Code. Clearly visible warning signs shall be placed on the fence and/or site perimeter advising of potential high voltage hazards.

E. In agricultural zoning districts, the facility shall be classified a Group 1 use for buffering and screening purposes under this Code. In the M district, ground-mounted facilities shall be classified a Group 6 use; however, buffering and screening shall be required only where abutting parcels have a Group 3 or lower intensity classification. Building-mounted facilities shall have the same intensity classification as the host use.

F. Where ground-mounted solar panels face abutting residentially developed or zoned parcels or public roadways and screening is not otherwise required under the provisions of this Code, the panels shall be made of glare reducing materials or shall be visually screened from said abutting parcels and roadways as follows:

1. In agricultural districts, the screening shall be comprised of evergreen plants with a minimum opacity of 75 percent at the time of planting. The plants shall be six feet in height or the height of the solar panels, whichever is less. Alternatively, an increased setback of 100 feet may be provided in lieu of screening.
2. In the M district, the screening shall be comprised of a solid fence or wall, chain link fence with opaque slates, or evergreen plants with a minimum opacity of 75

percent at the time of planting. The screening shall be six feet in height or the height of the solar panels, whichever is less.

The Administrator may waive these screening requirements in cases where equivalent or greater screening is provided by existing vegetation, fences or non-residential structures on the host parcel and/or abutting residential parcels or roadways.

G. Onsite power lines and interconnections shall be placed underground to the greatest extent possible.

H. Prior to preliminary site plan approval or construction plan where the preliminary process is waived, the applicant shall submit proof of notice to the utility company that operates the power grid where the solar energy production facility will be located of the intent to develop an interconnected power generation facility. Prior to site construction plan approval, the applicant shall submit proof of an executed interconnection agreement with the utility or other written proof of an agreement with the utility that construction can proceed.

I. A solar energy production facility shall be considered abandoned after a one-year period without energy production. The property owner shall be responsible for removing all energy production and transmission equipment and appurtenances within 120 days of abandonment.

J. Solar power generation facilities, which require certification under the Florida Electrical Power Plant Siting Act shall be allowed only in Planned Development districts, which specifically permit the use.

The applicable regulations are a minimum 50-foot setback from all property boundaries, a maximum height of 15 feet, security fencing along the perimeter and screening or a 100-foot setback along all perimeters. Due to the potential for a new road to be built across the subject property, an additional 50-foot setback may be required from both sides of the required 96-foot right-of-way.

## ECOLOGICAL FINDINGS

An ecological assessment of the subject property (Figure 1) was conducted to determine the likelihood of the presence of listed floral and faunal species and to delineate and describe existing upland and wetland plant communities.

### *Desktop Review*

Initially, a desktop review was conducted consisting of readily available information including recent aerial photography, the Soil Survey of Hillsborough County, Florida map (Figure 2), and the National Wetlands Inventory (NWI) map (Figure 3). An initial "aerial signature" map was created using aerial photo-interpretation. After the field survey of the subject property, a final map depicting the plant communities and land use was completed using the *Florida Land Use, Cover, and Forms Classification System* (FLUCFCS), Level III, of the Florida Department of Transportation (1999). The land covers and uses on the map were cross-referenced with the *Guide to the Natural Communities of Florida*, 2010 Edition, Florida Natural Areas Inventory (FNAI). The database of the FNAI was accessed for Hillsborough County to review the listed animals, plants, and plant communities that could potentially occur within or in the vicinity of the subject property. The *Atlas of Florida Vascular Plants*, Institute for Systematic Botany, University of South Florida, was consulted for the proper plant species taxonomic nomenclature. The *UF Digital Collections* of George A. Smathers Libraries with the University of Florida was searched for historic aerial photographs of the land. The Florida Fish and Wildlife Conservation Commission (FWC) Water Bird Colony Locator and Bald Eagle Nest Locator were accessed for the occurrence of any documented wading bird rookeries or bald eagle nest sites within the surrounding area.

### *Field Survey*

On April 12, 2017, Environmental Consulting & Technology, Inc. (ECT) conducted a field survey of the 199.04-acre subject property. The purpose of the survey was to identify existing upland and wetland habitats and their constituent species and search for the presence of any state and/or federally listed plant or animal species. The field survey was performed by an ECT ecologist by slowly traversing the more accessible areas of the property by vehicle and conducting pedestrian transects where vegetation or terrain made it necessary. It was warm, partly cloudy, and breezy during the survey. The following sections describe the vegetation and land use, wildlife, and listed species found at the subject property.

***Results-Vegetation and Land Use***

Land use and cover maps were prepared prior to the field inspection and, based on FLUCFCS Level III mapping, were modified to more accurately depict the conditions observed in the field. Special emphasis was placed upon searching for listed plants and animal species reported by the FNAI database for Hillsborough County. All plants and animals listed by the various agencies for the State of Florida and the U.S. Fish and Wildlife Service were sought based upon preferred habitat availability on the subject property. A description and quality assessment of each habitat type was recorded.

Figure 4 is a land use and vegetative cover map depicting the habitat types and land uses by FLUCFCS codes observed on the subject property. The use of the FLUCFCS 600 codes does not imply formal wetland jurisdictional lines. The delineations of land cover and use types were done by aerial photointerpretation, direct observation, and the use of other available data resources such as the NWI map and the Soil Survey of Hillsborough County, Florida (i.e., Figures 2 and3, respectively). Land use and cover types were mapped and classified into 6 FLUCFCS categories— 215-Field Crops (Hay) (189.27-acres), 260-other open lands, rural (1.79-acres), 425-temperate hardwoods (5.15-acres), 618-willow and elderberry (0.53-acre), 643-wet prairies (1.11-acres), and 814-access roads (1.19-acres).

The following is a brief description of each FLUCFCS plant community type or land use that occurs on the subject property. Dominant plant species are listed in the descriptions.

**200 AGRICULTURE**

**215 Field Crops (FNAI: Agriculture) –** Field crops generally refer to crops raised for grains or animal forage (grasses). The hayfields on the Cecil B. James property consist of two varieties of bermudagrass (*Cynodon dactylon* vars. Florakirk and Tifton 44) selected for horses and cattle. During the growing season, the fields are harvested about every 6 weeks and dried for baling. Approximately

95 percent of the subject property land use is hayfields. Very minor constituents of the hayfields include bahiagrass (*Paspalum notatum*), cutleaf evening primrose (*Oenothera lacinata*), Mexican clover (*Richardia brasiliensis*), dock (*Rumex fascicularis*), and pepperweed (*Lepidium virginicum*). Scattered live oaks (*Quercus virginiana*) are present in the hayfields.

**260 Other Open Lands, Rural (FNAI: Agriculture) –** This category generally refers to rural land with undetermined use. On the Cecil B. James property, this category is used for a small portion of land used for storing farm equipment, staging maintenance/harvesting, loading trucks, and other support activities (referred to as the compound). Vegetation in this area is generally similar to the hayfields.

**400 UPLAND FORESTS**

**425 Temperate Hardwoods (FNAI: Mesic Hammock) –** Temperate hardwoods is a general term referring to any species of broadleaf trees that shed their leaves on an annual basis. On the subject property, two areas have recruited a mix of broadleaf trees. The first area is a ring of trees surrounding a relic sinkhole; the second is near the center of the tract where trees became established in a remnant of citrus grove. Both areas contain a mix of native and exotic (non-native) species. Native trees include live oak, laurel oak (*Quercus laurifolia*), elm (*Ulmus americana*), black cherry (*Prunus serotina*), cabbage palm (*Sabal palmetto*), and red mulberry (*Morus rubra*). The primary non-native plant species is an invasive tree species, chinaberry (*Melia azedarach*), which is listed on the Florida Exotic Pest Plant Council invasive plant species list. A few loquat (*Eriobotrya japonica*) and other weedy trees were also observed.

**600 WETLANDS**

**618 Willow and Elderberry (FNAI: Sinkhole) —** A relic sinkhole on the property apparently holds water during seasonal rainfall. Stain lines indicate about eight feet of inundation. Historic aerial photographs show that in the 1930s and 1940s, the sinkhole looked more like a lake or pond in that no trees existed in or around it. Currently, the bottom of the sinkhole is concave and non-vegetated indicating extended periods of inundation which prevents the establishment of wetland plant species. Coastalplain willow (*Salix caroliniana*) and elderberry (*Sambucus nigra* subsp. *canadensis*) have established on the lower slopes as well as maiden fern (*Thelypteris kunthii*) and guineagrass (*Urochloa maxima*). Considerable vine cover and deadfall and some debris are present.

**643 Wet Prairies (FNAI: Wet Prairie)** — This herbaceous wetland type has predominately grassy vegetation and is a depression between topographic highs. The area is ditched to drain to the north and offsite. The plant community of this area is composed of bahiagrass, flatsedges (*Cyperus* spp.) manyflower marshpennywort (*Hydrocotyle umbellata*) and dotted smartweed (*Persicaria punctata*).

**800 TRANSPORTATION, COMMUNICATIONS AND UTILITIES**

**814 Roads and Highways (FNAI: Road)** — a main unpaved, access road is present onsite connecting Taylor Road to the compound area.

***Results-Wildlife***

The majority of the highly altered subject property consists of bermudagrass hayfields. It is evident from the review of historic aerial photographs that citrus was the main crop for decades. Prior to clearing in the 1940s, the land appears to have been scrub or sandhill. During the site survey, there was very little wildlife present, except for several cattle egrets (*Bubulcus ibis*) foraging in the pasture. Mounds of fresh soil indicated that pocket gophers (*Geomys pinetus*) were ubiquitous throughout. There were some passerines such as tree swallows (*Tachycineta bicolor*) and American crows (*Corvus brachyrhynchos*) also present. Two gopher tortoise (*Gopherus polyphemus*) burrows were present, but damaged by digging. The property caretaker stated that a coyote (*Canis latrans*) had dug out the two gopher tortoise burrows and had used them as dens. There were few signs of other herpetofauna or mammals observed. The above-referenced wildlife species as well as others in the area have become adapted to the altered condition of the subject property and regional wildlife populations should not be significantly affected by the proposed activities.

***Results-Listed Species***

No state or federally listed plant or animal species were observed on the subject property. Continual agricultural activities over the past six to seven decades have displaced the native habitats and discouraged wildlife usage of the land. The closest documented bald eagle nest site found on the FWC Eagle Nest Locator is located approximately 2.06 miles to the north-northeast of the subject property (HL013; last active in 1997; last surveyed 2013); the closest most recently used bald eagle nest site is 2.44 miles to the northeast (HL052, known to be active in 2014; last surveyed in 2013). No eagle nest sites were observed on or near to the subject property. The FWC Water Bird Colony Locator indicates that the closest water bird colony is approximately 1.5 miles to the northeast of the subject property (Id #611169; FID 348; last surveyed in the 70s; unknown). The closest active colonies are 8.5 miles to the west-southwest (Id #611308; FID 360; last surveyed in the 1990s) and seven miles to the southeast (Id # 615330; FID 585; last surveyed in the 1990s) The closest wood stork colony was recorded as being approximately 11 miles northwest of the subject property (i.e., Id #611310; last surveyed as active in the 90s; containing double-crested cormorants [*Phalacrocorax auritus*], wood storks [*Mycteria americana*], great egrets [*Ardea alba*], and brown pelicans [*Pelecanus occidentalis*]; 250 to 500 birds). No water bird colonies were observed on or in the immediate vicinity of the subject property.

The FNAI Species Tracking List identified 17 listed plants and 27 listed animals (one fish, 10 reptiles, 14 birds, and two mammals) as occurring within Hillsborough County, Florida. The potential for occurrence of the listed species on the subject property was determined by a habitat analysis, literature review, and ground surveys. Based upon an evaluation of habitat preference and distribution of species, out of the 44 listed plant and animal species recorded for Hillsborough County, Florida, four listed animal species (two reptiles and two birds) and two delisted, but still protected bird species, were identified as expected or possible to occur within or in proximity to the subject property (see Table 1). Based upon the detailed analysis and survey conducted, no adverse effects to federally or State listed threatened or endangered animal species are anticipated from the proposed action.

***Summary***

The subject property is in a highly altered condition with only marginal habitats to support wildlife. No listed plant or animal species have been identified on or in the immediate vicinity of the project site. Therefore, no adverse impacts are expected to local or regional populations of game species, species of special concern or commercial importance, or threatened or endangered species occurring or potentially occurring on or in the vicinity of the subject property. Less than one percent of the subject property is wetland and these areas are disturbed. Any project-related wetland impacts will require wetland permitting. There do not appear to be any major ecological issues that would result in denial of a wetland permit for construction, if the wetlands are to be developed or impacted.

# TABLES

Table 1. Listed Wildlife Species Observed or Having Potential to Occur on the Cecil B. James Property

| Species | Listed Status | Estimated Likelihood of Occurrence | | | | |
|---|---|---|---|---|---|---|
| | State/Federal | Observed | Expected | Possible | Unlikely | Comments |
| **Birds** | | | | | | |
| Florida Sandhill Crane *(Antigone* (*Grus) canadensis pratensis* ) | ST/ U.S Migratory Bird Treaty Act | | X | | | Hayfields offer forage, but sparse other resources nearby |
| Southeastern American Kestrel (*Falco sparverius paulus* ) | ST | | X | | | Open pastureland for hunting |
| Osprey (*Pandion haliaetus* ) | Migratory Bird Treaty Act (16 U.S.C. 703-712) & Chapter 68A, F.A.C. | | X | | | Ospreys are generally found near lakes and waterbodies in Florida |
| Bald eagle *(Haliaeetus leucocephalus)* | protected under 16 U.S.C. 668-668d | | X | | | No large trees for nesting, but Lake Thonotosassa nearby for fishing. |
| **Reptiles** | | | | | | |
| Eastern Indigo Snake (*Drymarchon couperi* ) | FT | | | X | | These snakes have large ranges and may be found in various uplands; GT commensal species |
| Gopher Tortoise (*Gopherus polyphemus* ) | ST | | | X | | Small area of upland soils, but habitat displaced by agriculture; 2 burrows destroyed by coyotes. |

**Wildlife: FE, FT** - Federally listed as Endangered, Federally listed as Threatened, US Fish and Wildlife Service; **ST, SSC**- State listed as Threatened, State listed as Species of Special Concern.

**Observed** - animal or positive evidence of animal seen; **Expected** - Habitat present within animal's range, probable that animal would be observed; **Possible** - Habitat degraded, but animal may use on a limited basis; **Unlikely** - Habitat displaced, incidental use only by animal.

Table 2. Listed Plant Species Observed or Having Potential to Occur on the County Line Farms Property

Table 2. Listed Plant Species Observed or Having Potential to Occur on the Cecil B. James Property

| Species | Listed Status | Estimated Likelihood of Occurrence | | | | |
|---|---|---|---|---|---|---|
| | State/Federal | Observed | Expected | Possible | Unlikely | Comments |
| **Plants** | | | | | | |
| Pine-woods Bluestem (*Andropogon arctatus* ) | ST | | | | X | Small area of xeric habitat, but impacted by cattle. |
| Sand Butterfly Pea *(Centrosema arenicola)* | SE | | | X | | Habitat degraded by becoming overgrown; cattle present. |
| Florida Goldenaster (*Chrysopsis floridana* ) | FE/SE | | | X | | Habitat degraded by becoming overgrown; cattle present. |
| Tampa Vervain *(Glandularia tampensis)* | SE | | | | X | Habitat degraded by becoming overgrown; cattle present. |
| Nodding Pinweed (*Lechea cernua* ) | ST | | | | X | Small area of xeric habitat, but impacted by cattle. |
| Giant Orchid (*Pteroglossaspis ecristata* ) | ST | | | | X | Infrequently, populations may persist in pastures. |
| Large-plumed Beaksedge (*Rhynchospora megaplumosa* ) | SE | | | | X | Small area of xeric habitat, but impacted by cattle. |
| Britton's Beargrass (*Nolina brittoniana* ) | FE/SE | | | | X | Small area of xeric habitat, but impacted by cattle. |

**Plants: SE, ST -** State listed as Endangered or Threatened by the Florida Department of Agriculture Services, Division of Plant Industry; **FE, FT** - Federally listed as Endangered or Threatened

**Observed** - Positive ID plant seen; **Expected** - Habitat is appropriate for plant's range, probable that plant would be present; **Possible** - Habitat degraded, but plant may be found as a relict population; **Unlikely** - Habitat displaced, can no longer support life cycle of plant.

# FIGURES

Q:\projects\Cecil_Property\170265\0200\Site_Location.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator istebnisky 4/21/2017 2:13:04 PM

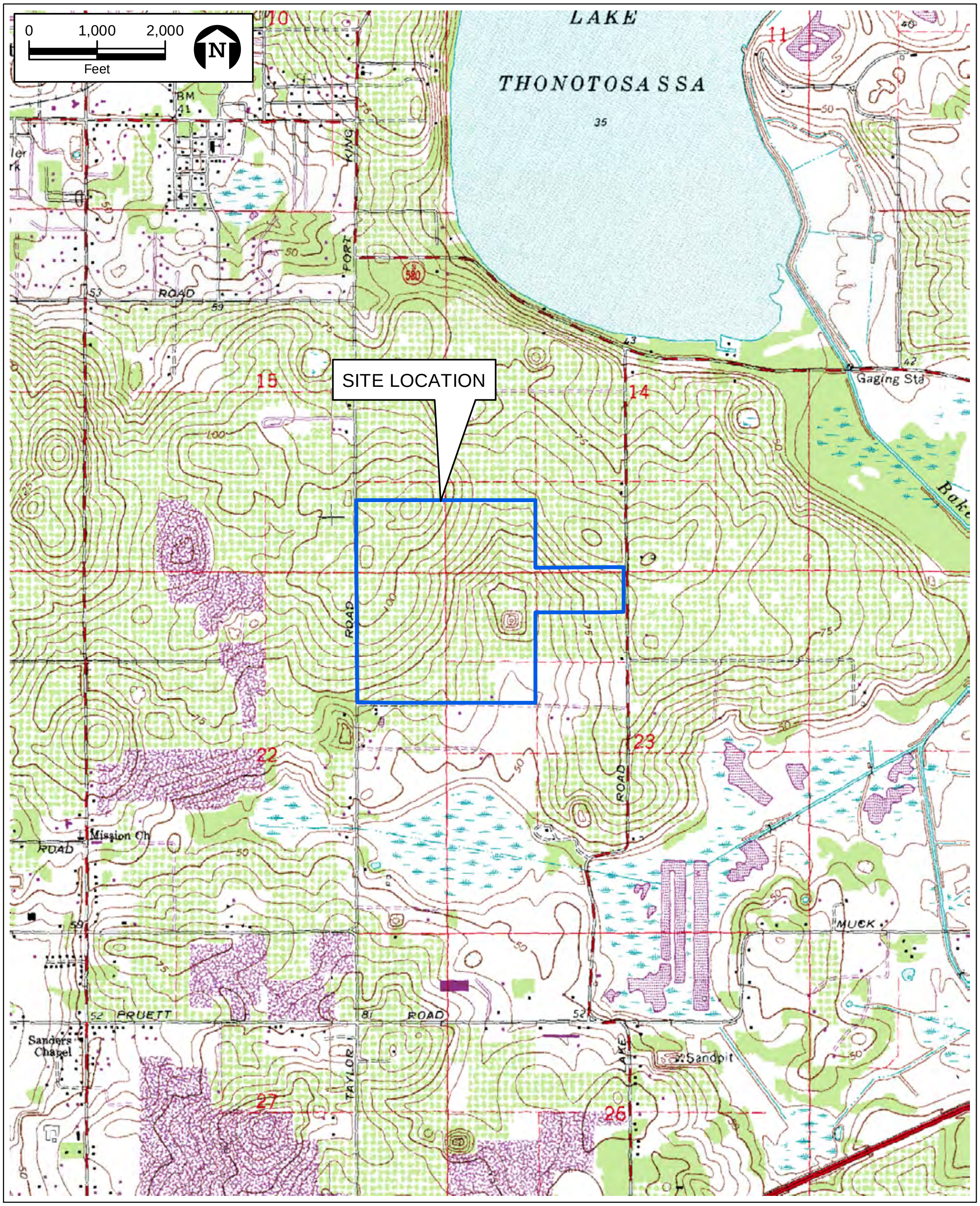
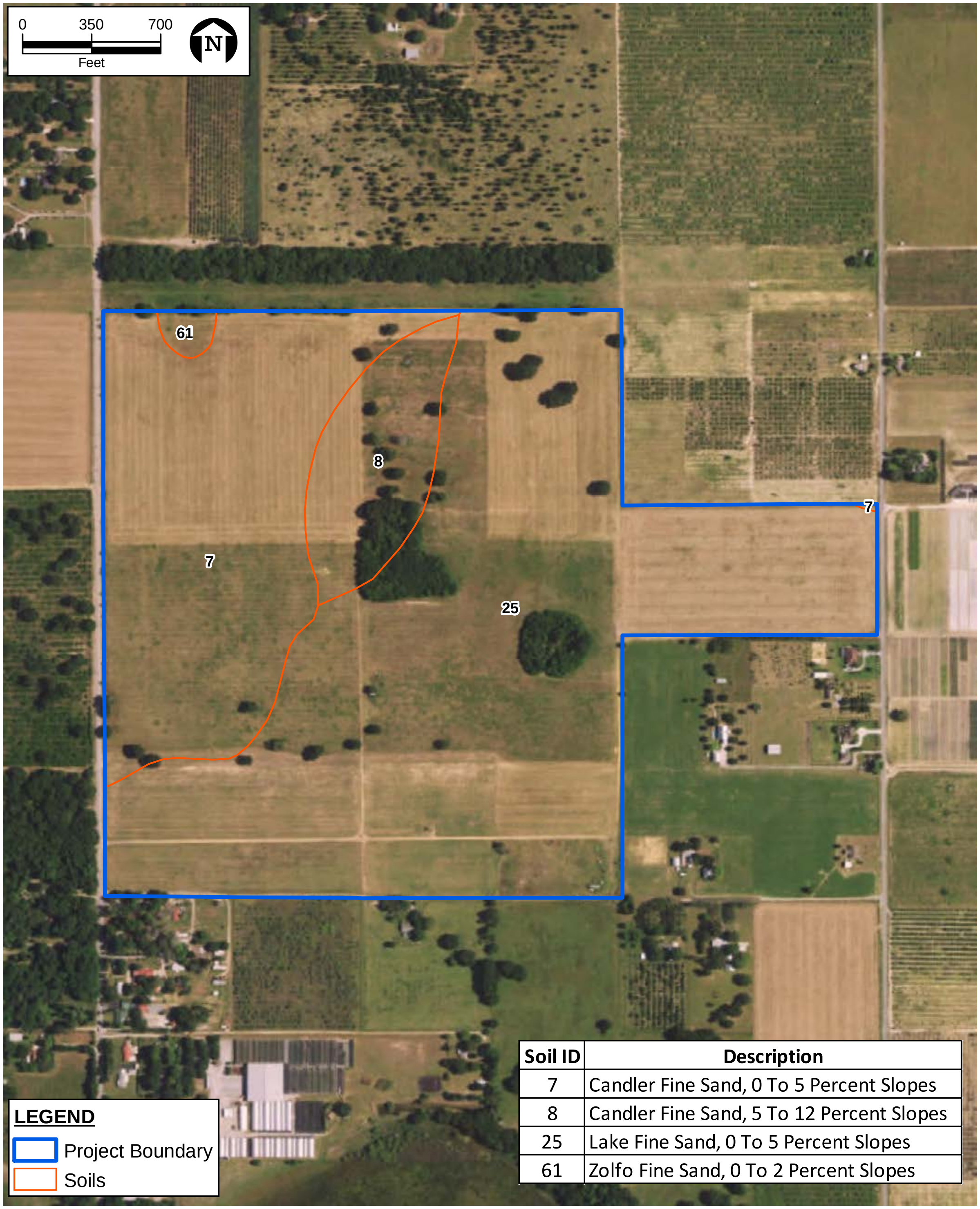



FIGURE 1.
SITE LOCATION MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: Labins.org USGS Quad Map of Thonotosassa, FL, 1974; Hillsborough County PA, 2014; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

Q:\projects\Cecil_Property\170265\0200\Soils_map.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator jstebnisky 4/21/2017 4:05:13 PM




| Soil ID | Description |
|---|---|
| 7 | Candler Fine Sand, 0 To 5 Percent Slopes |
| 8 | Candler Fine Sand, 5 To 12 Percent Slopes |
| 25 | Lake Fine Sand, 0 To 5 Percent Slopes |
| 61 | Zolfo Fine Sand, 0 To 2 Percent Slopes |

FIGURE 2.
SOILS MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; NRCS, 2016; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

Q:\projects\Cecil_Property\170265\0200\nwi_map.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator jstebnisky 4/21/2017 2:41:15 PM

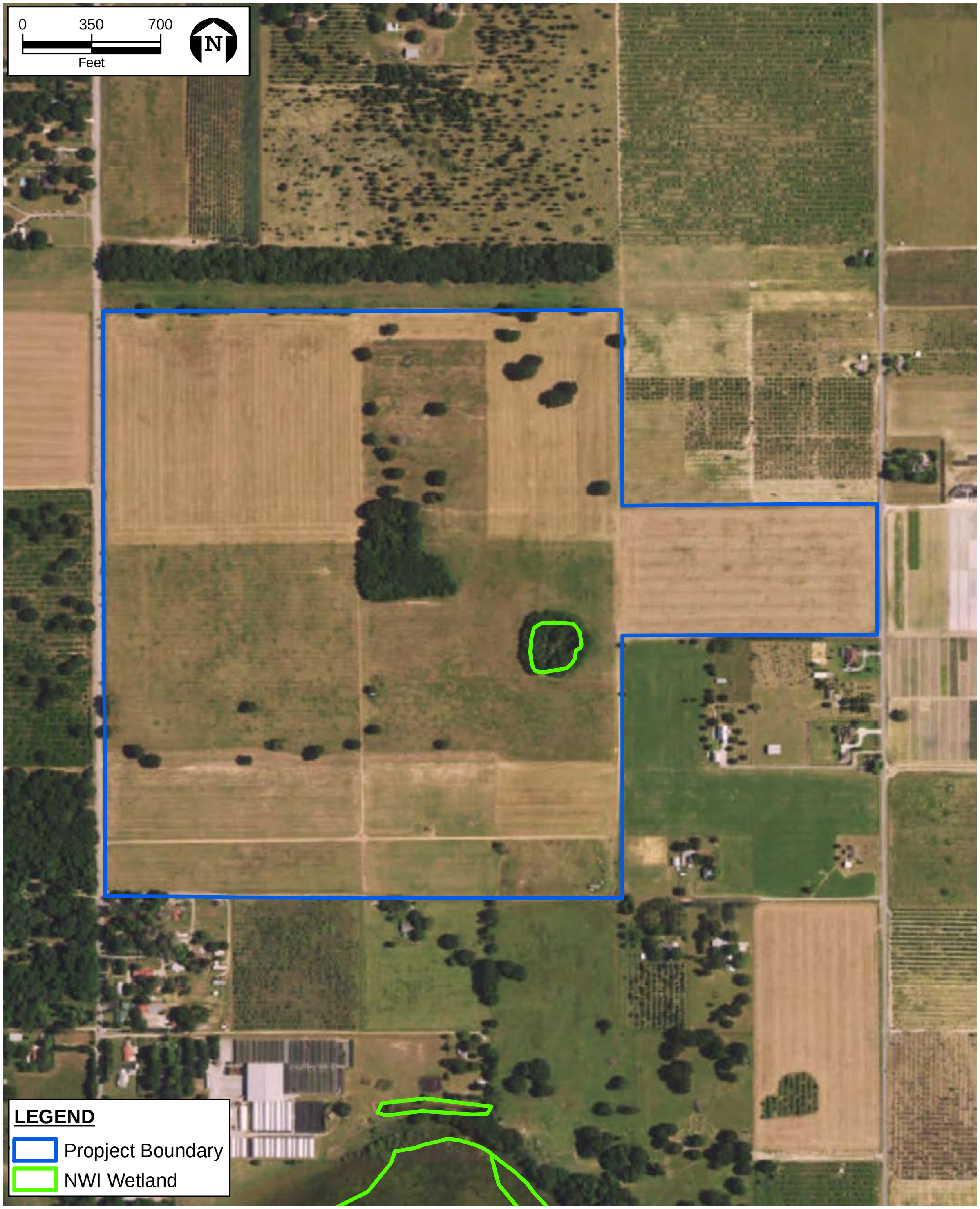
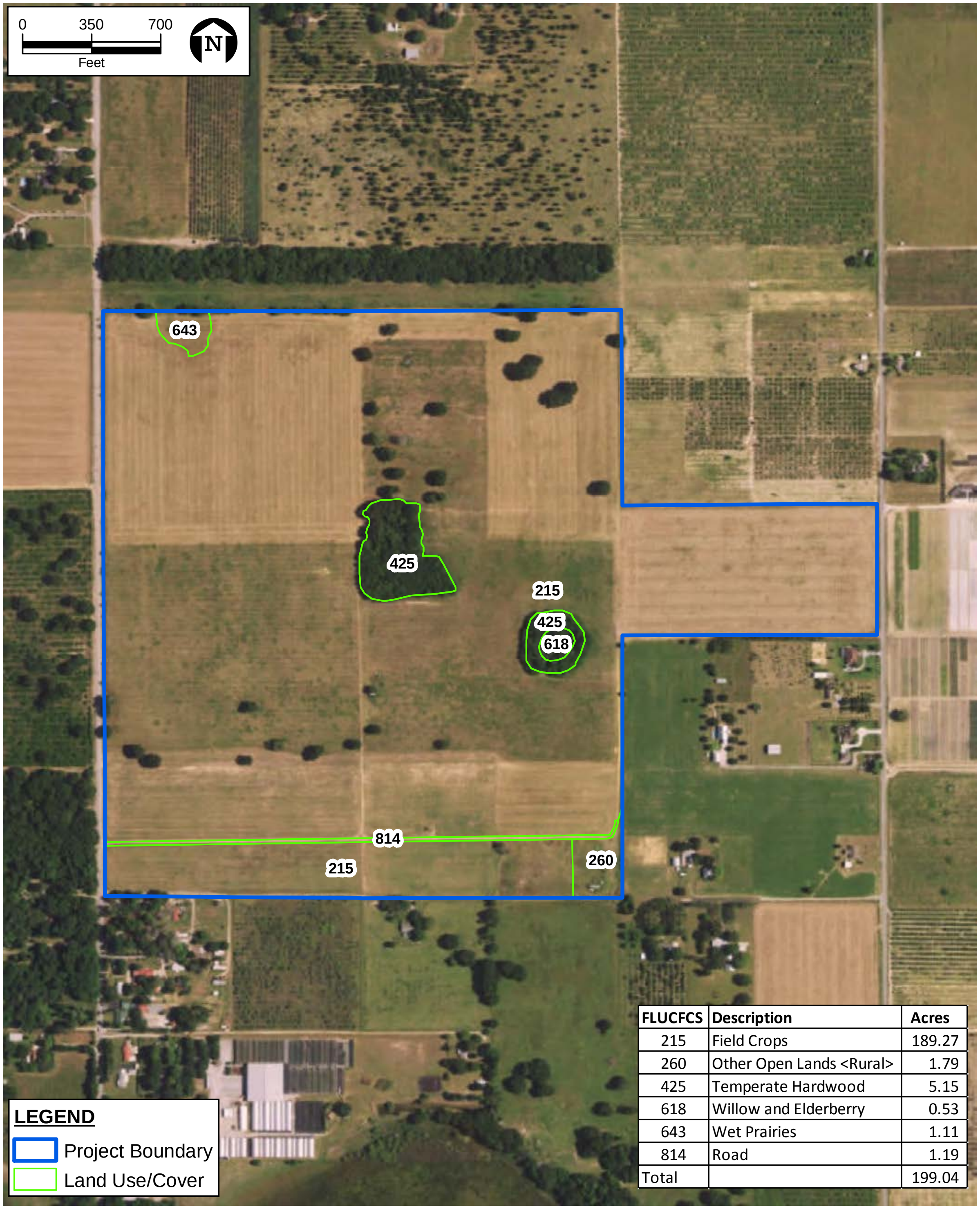



FIGURE 3.
NATIONAL WETLANDS INVENTORY MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; NWI, 2016; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

Q:\projects\Cecil_Property\170265\0200\LandUse.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator jstebnisky 4/21/2017 2:44:17 PM




| FLUCFCS | Description | Acres |
|---|---|---|
| 215 | Field Crops | 189.27 |
| 260 | Other Open Lands <Rural> | 1.79 |
| 425 | Temperate Hardwood | 5.15 |
| 618 | Willow and Elderberry | 0.53 |
| 643 | Wet Prairies | 1.11 |
| 814 | Road | 1.19 |
| Total | | 199.04 |

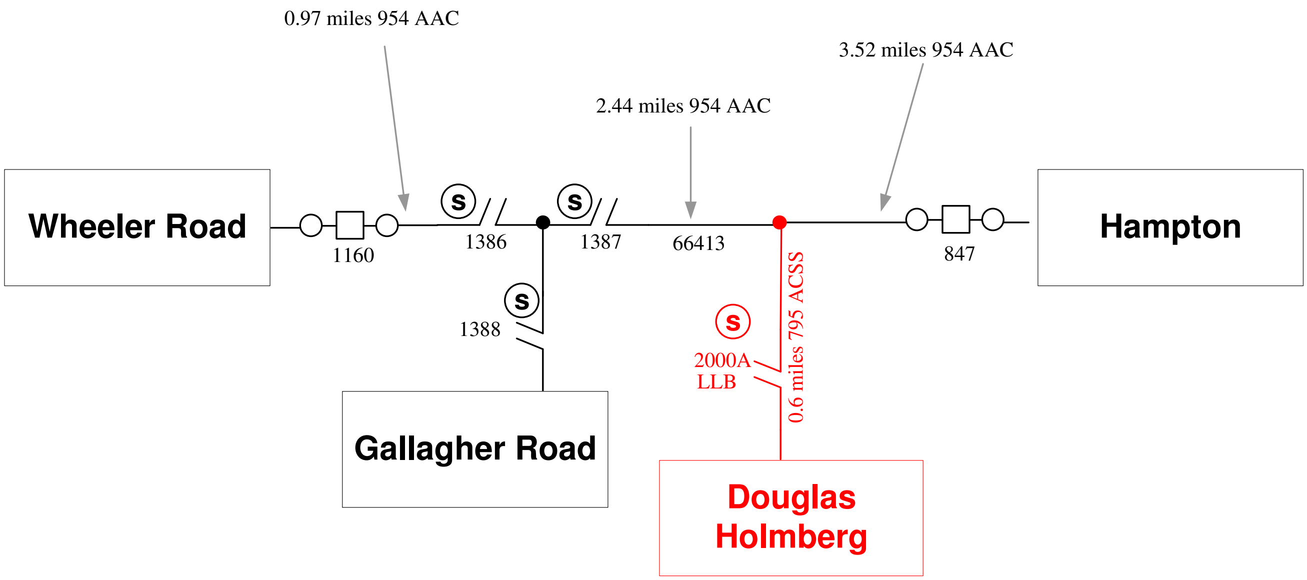
FIGURE 4.
LAND USE/COVER MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; ECT, 2017.

Environmental Consulting & Technology, Inc.

| TITLE: **Douglas Holmberg Solar Facility** | **2018** |
|---|---|
| **DESCR:** Tap circuit 66413 to connect to new Meter Station for Douglas Holmberg Solar Facility<br>Install a 2000A LLB supervisory transmission line switch on Circuit 66413 north of new tap. | **IN SVC BY:**<br>**Jun**<br>**See Construction Schedule** |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

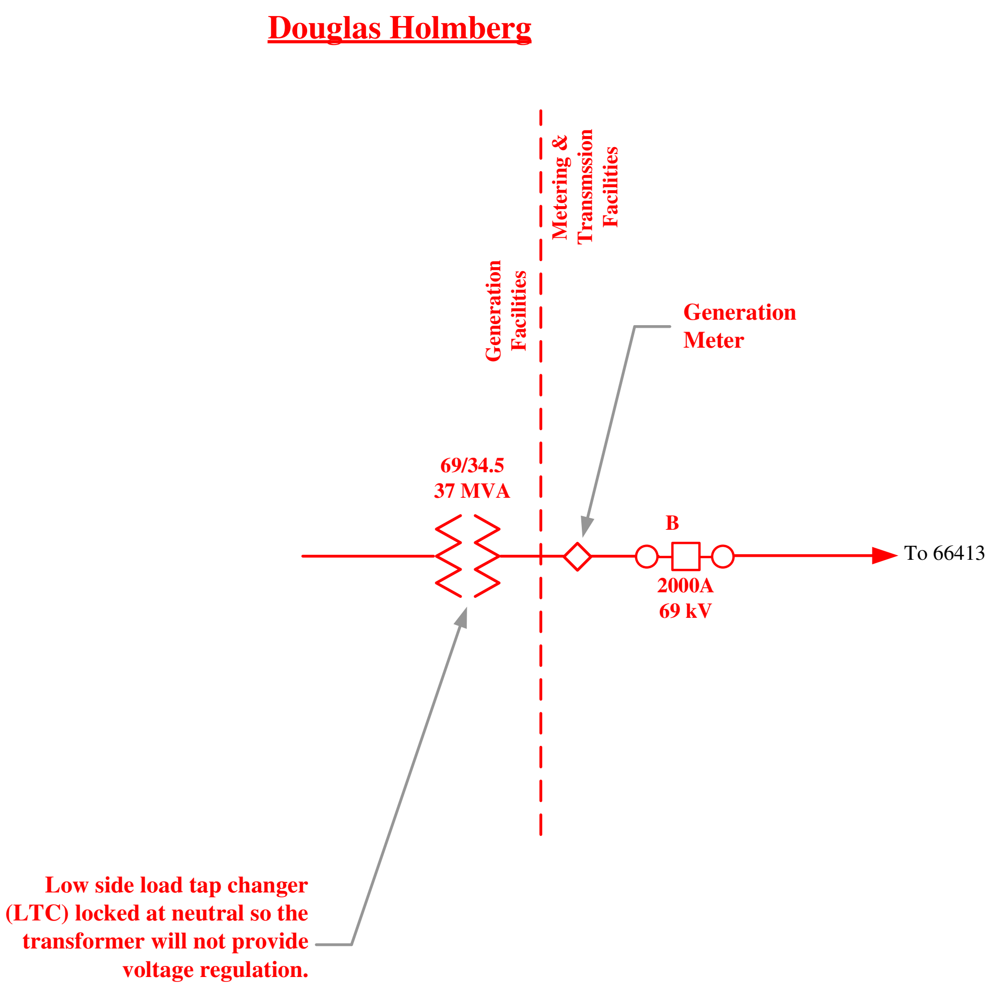



EDCP: PCA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1964.000** | **T** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

| | |
|---|---|
| **TITLE:** **Douglas Holmberg Solar Facility** | **2018** |
| **DESCR:** Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A breaker will also be installed in station. | **IN SVC BY:** **Jun** **See Construction Schedule** |
| **NOTES:** Douglas Holmberg Solar Facility will be tapped off 69 kV circuit 66413 and is expected to have an output of 25MW | |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**



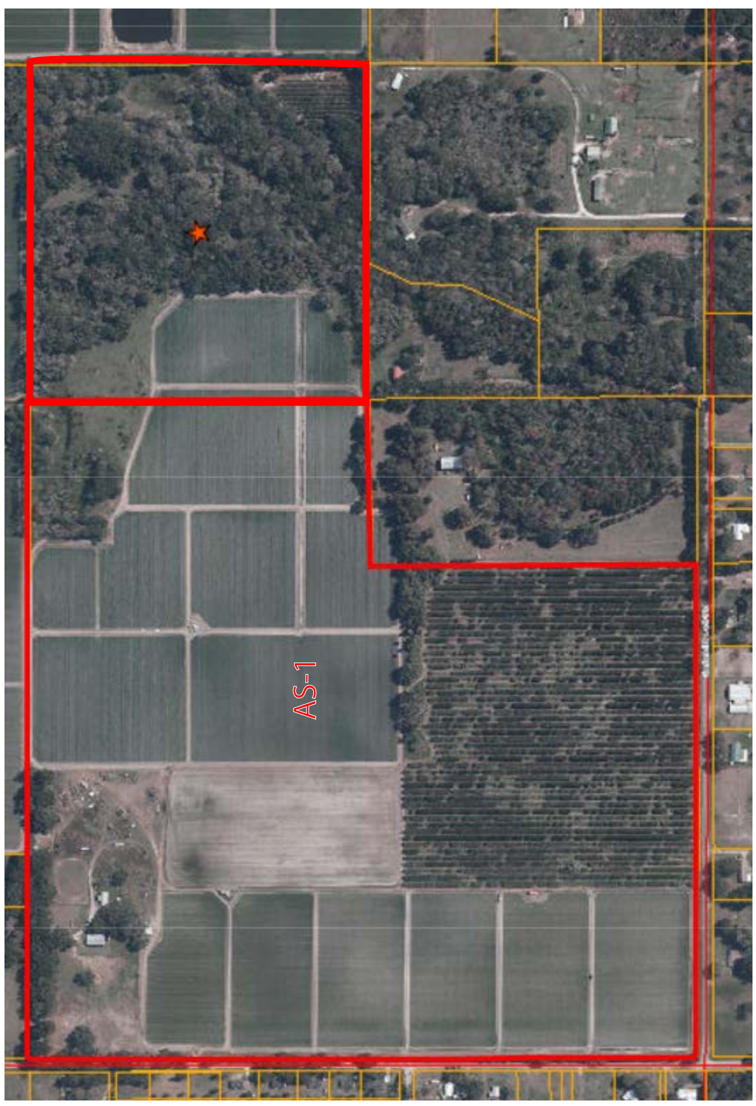

EDCP: PCA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1964.000** | **S** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

Holmberg
176± Acres on Sydney Washer Road
Aerial Photo Showing Topography


NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Holmberg
176± Acres on Sydney Washer Road
Existing Land Use - AS-1




NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Holmberg
176± Acres on Sydney Washer Road
Potential Wetlands Area


NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

# INTERCONNECTION INFORMATION

**Little Diehl:**

Site is across the street from TEC's Gulf City substation

Construct 0.25 mile 69 kV line from site to substation

**JayMar:**

Polk-Aspen 2130kV (230401) line runs across property

Loop 230402 with a 3 position 230 kV ring buss at project site

**Loop Farms:**

Construct 3 miles 69kV line to intersect future Mines – Balm 69 kV substation

**P2:**

Construct 4 mile 69 kV line to tap into circuit 66658

**Montesco:**

Circuit 66603 runs across site

Loop/Tap 69 kV line at site

**Cecil B James:**

Circuit 66024 runs across site

Loop/Tap 69 kV line at site

**Holmberg:**

Construct 0.6 mile 69 kV line along road right of way and tap into circuit 66413

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED:  OCTOBER 16, 2017

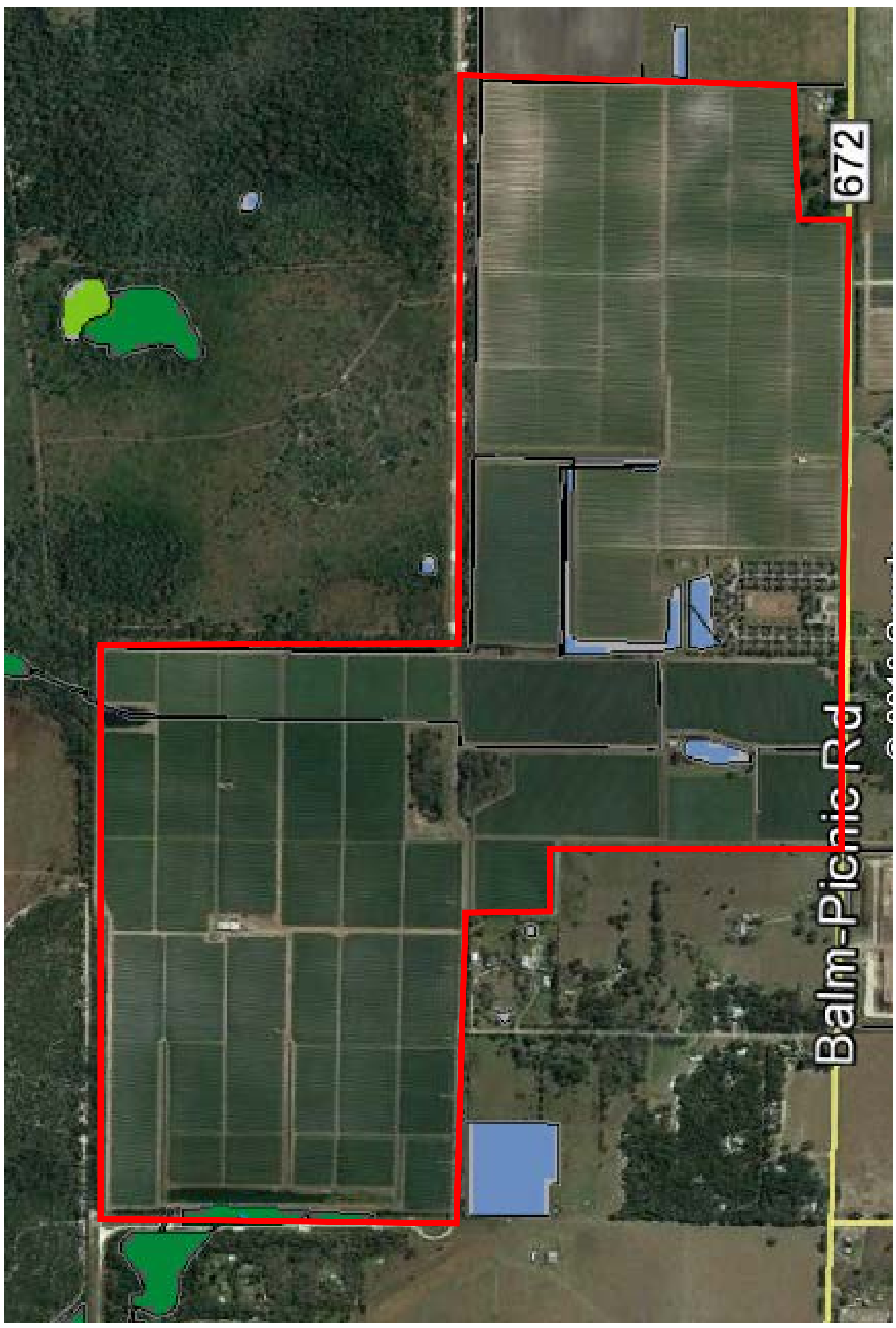
Jaymar Farms
554± Acres on Dupree Road
Aerial Photo Showing Topography


NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Jaymar Farms
554± Acres on Dupree Road
Existing Land Use - AR


NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

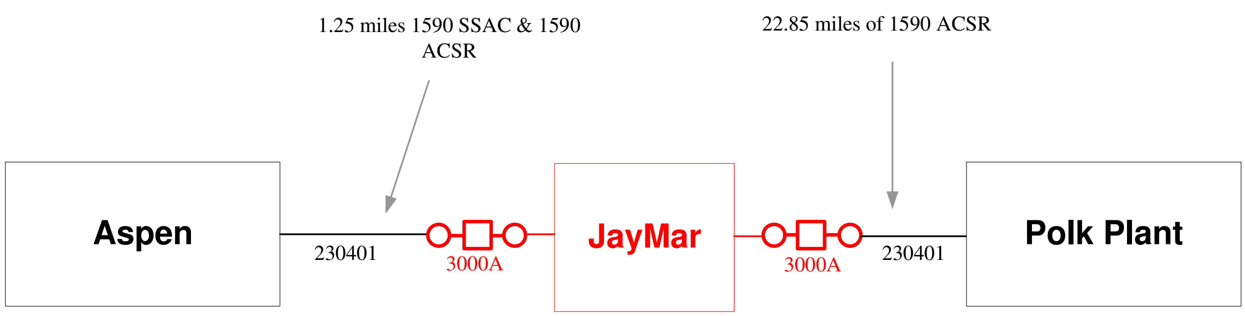
Jaymar Farms
554± Acres on Dupree Road
Potential Wetlands Area




NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

| **TITLE:** JayMar Solar Facility | **2018** |
|---|---|
| **DESCR:** Loop 230401 into the JayMar Solar Site. A 4-position 230 kV ring-bus will be constructed at the project site to accommodate the interconnection. Any additional conductor used to loop the site in/out of 230401 shall not limit the ratings of 230401 | **IN SVC BY:** **Jun** See Construction Schedule |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

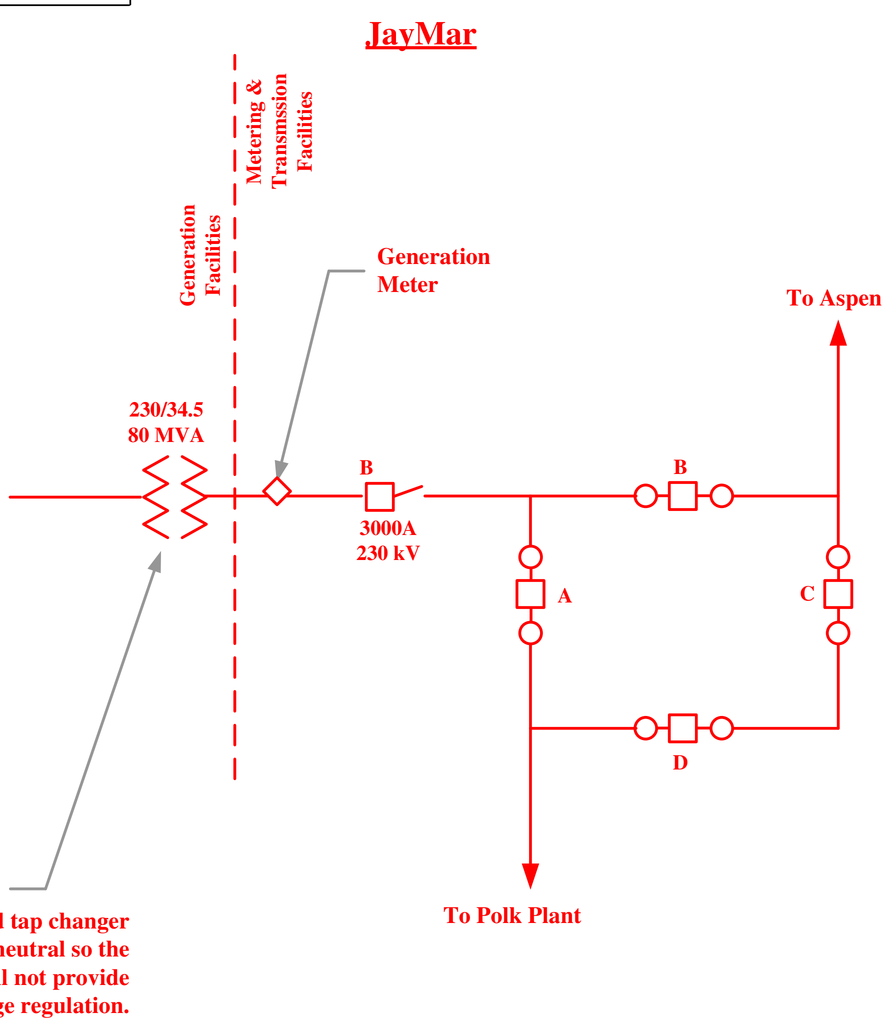



EDCP: PCA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1962.000** | **T** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

| TITLE: **JayMar Solar Facility** | **2018** |
|---|---|
| **DESCR:** Metering station contains a 230/34.5 kV 80 MVA. A 230 kV generation meter, CTs, PTs and a 3000A, 230 kV circuit switcher and a 4-position ring-bus will be constructed. The breakers utilized shall be 3000A, 63kA with 3000A disconnects | **IN SVC BY:** **Jun** See Construction Schedule |
| **NOTES:** Aspen and Polk should not shall not share a common breaker to avoid a breaker failure taking both lines out of service. | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

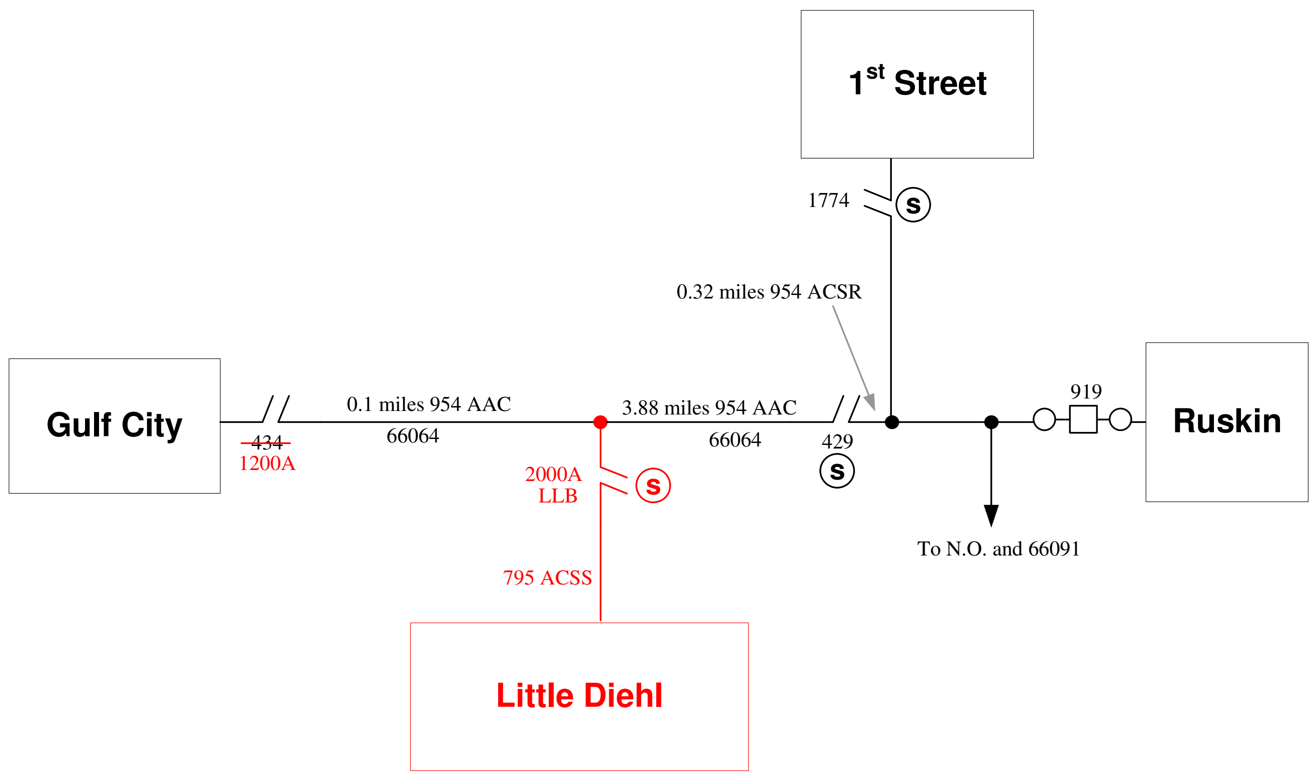



EDCP: PCA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: 1962.000 | S |
| | SUB #: ISSUE DATE: 04/18/2017 | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

| | |
|---|---|
| **TITLE: Little Diehl Solar Facility** | **2018** |
| **DESCR:** Tap circuit 66064 to connect to new Meter Station for Little Diehl Solar Facility<br>Install a 2000A LLB supervisory transmission line switch on Circuit 66064 north of new tap. | **IN SVC BY:**<br>**Jun**<br>**See Construction Schedule** |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**




EDCP: SHA

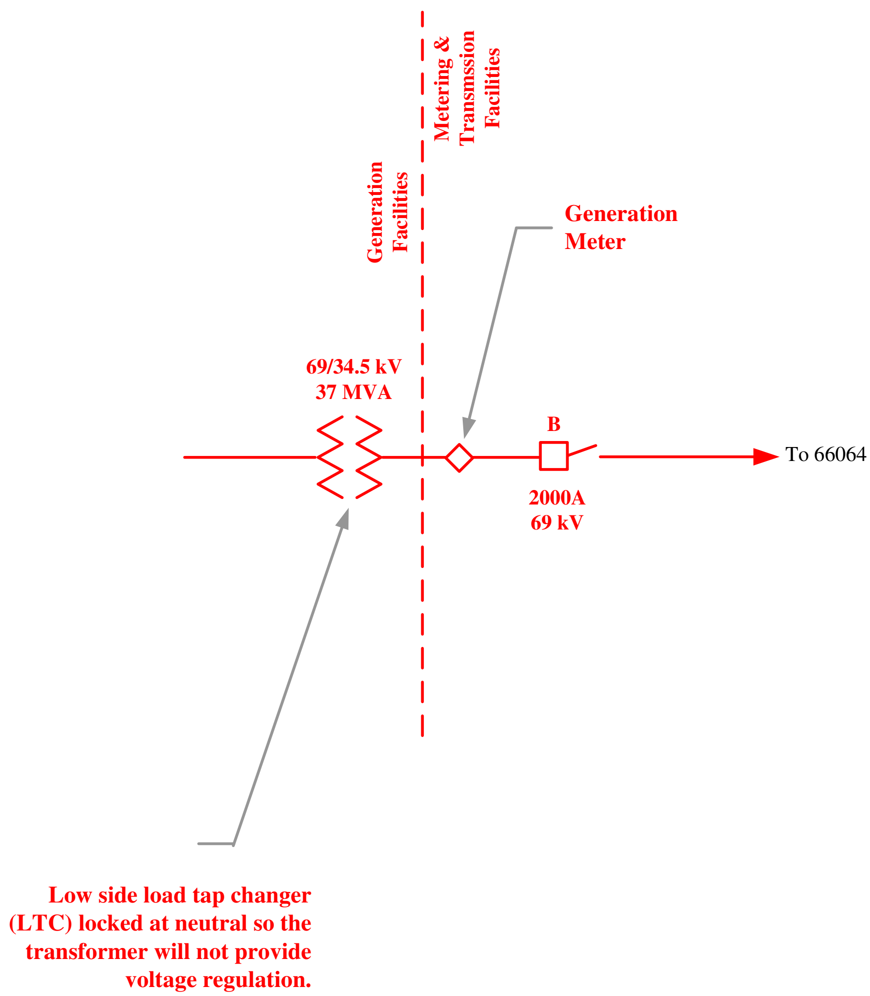
| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1961.000** | **T** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

| | |
|---|---|
| **TITLE:** **Little Diehl** | **2018** |
| **DESCR:** Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station. | **IN SVC BY:** **Jun** See Construction Schedule |
| **NOTES:** Little Diehl Solar Facility will be tapped off 69 kV circuit 66064 and is expected to have an output of 21 MW | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

## Little Diehl



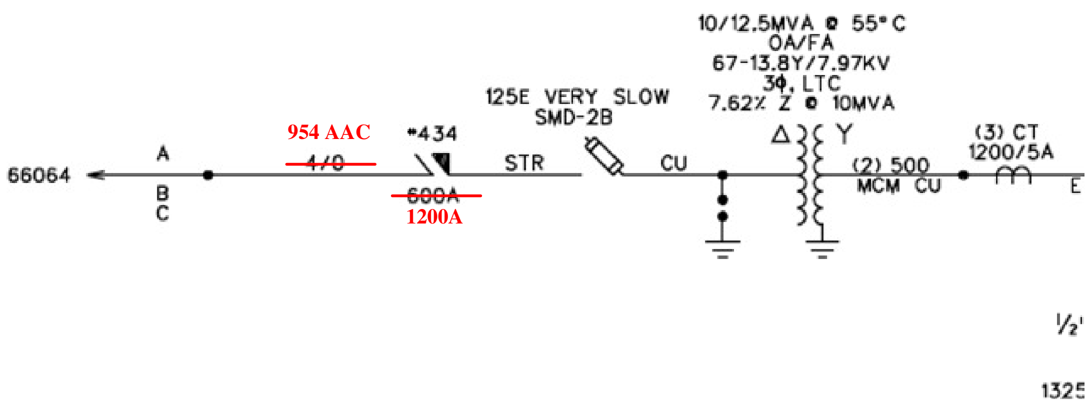

EDCP: SHA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1961.000** | **S-1** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

| | |
|---|---|
| **TITLE:** **Little Diehl** | **2018** |
| **DESCR:** Upgrade 4/0 string bus to 954 AAC and 600A switch # 434 to 1200A increasing the rating on First Street Tap – Gulf City to at least 1010A | **IN SVC BY:** **Jun** **See Construction Schedule** |
| **NOTES:** Little Diehl Solar Facility will be tapped off 69 kV circuit 66064 and is expected to have an output of 21 MW | |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

## Gulf City

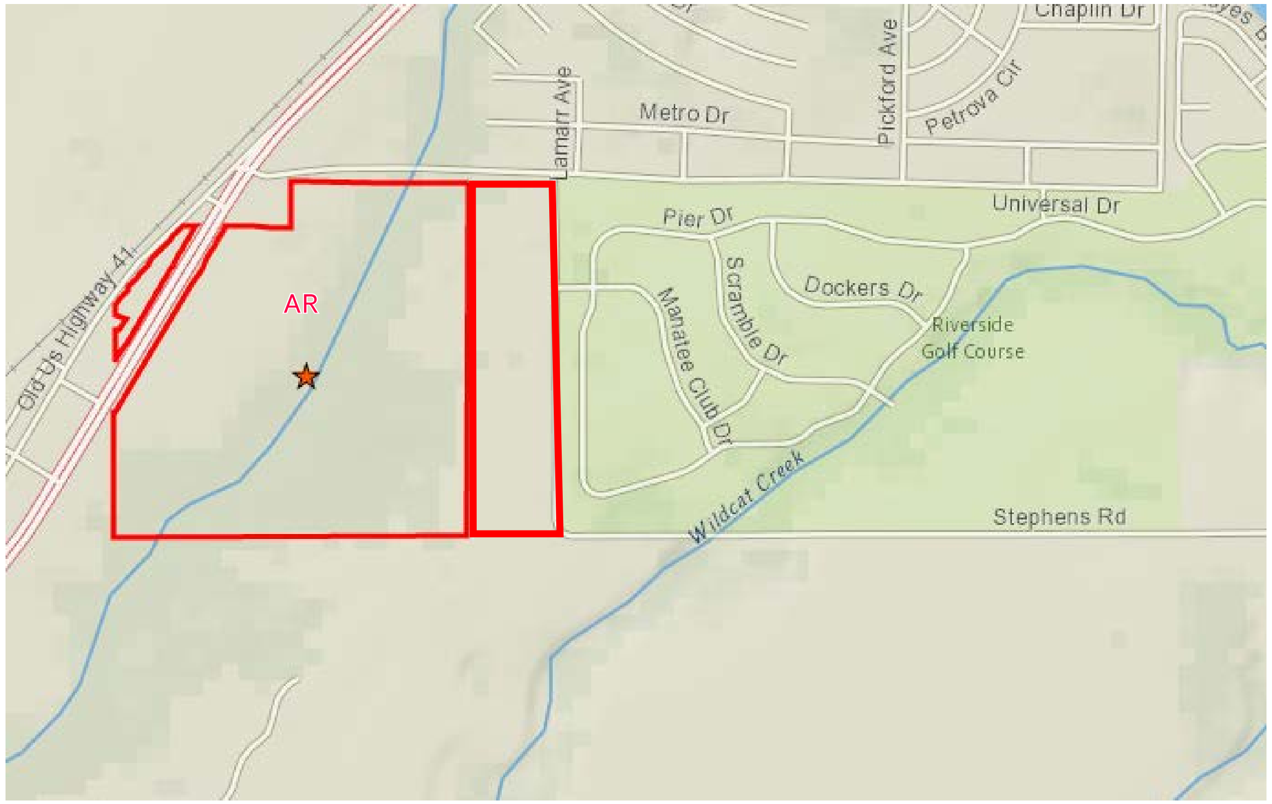



EDCP: SHA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1961.000** | **S-2** |
| | SUB #: **278D** ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

Frank Diehl
187± Acres on Old U.S. Highway 41
Aerial Photo Showing Topography

Frank Diehl
187± Acres on Old U.S. Highway 41
Existing Land Use - AR




NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Frank Diehl
187± Acres on Old U.S. Highway 41
Potential Wetlands Area

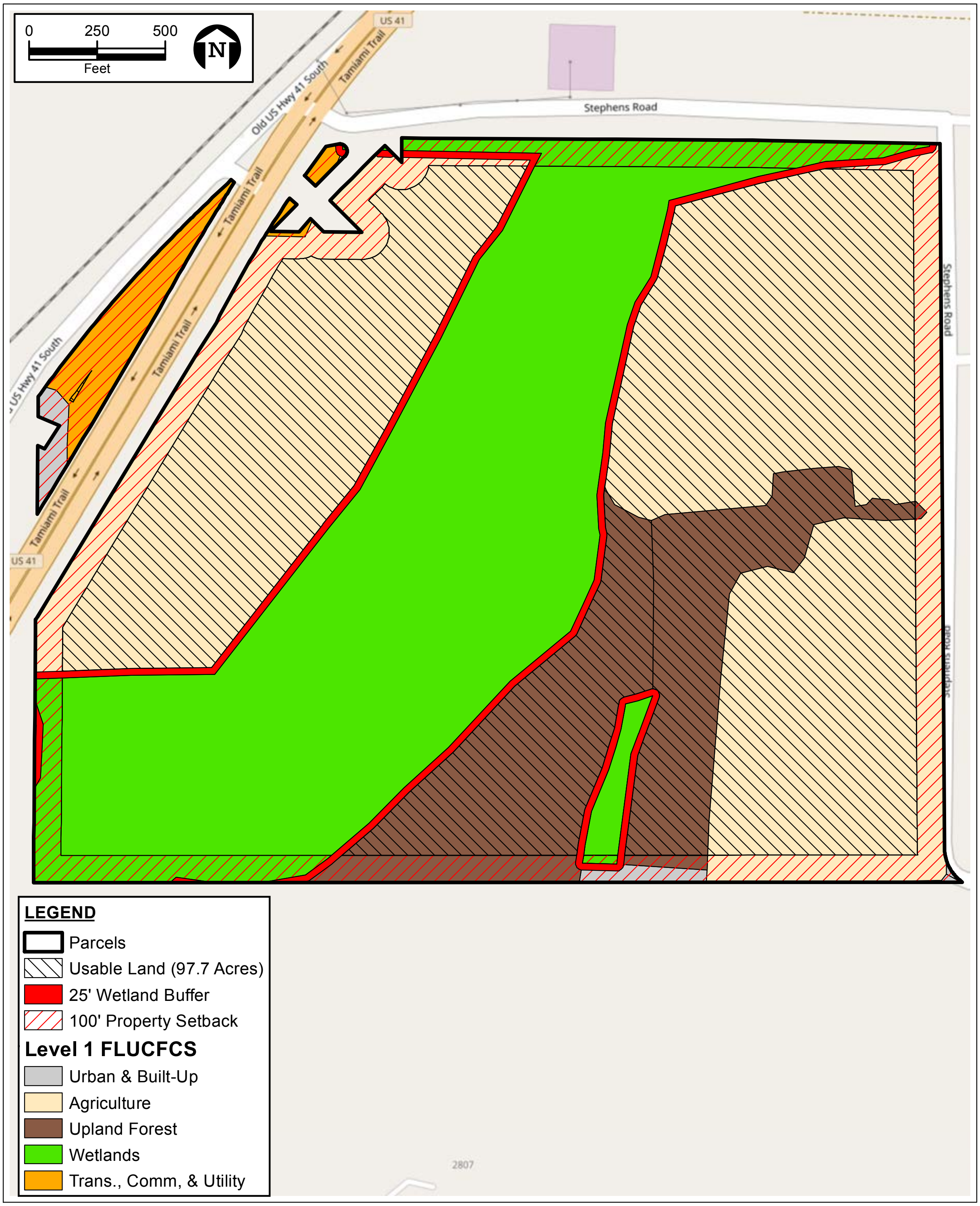

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

2/1/2017 3:37:24 PM


CONSTRAINT MAP WITH AERIAL
PARCEL NEAR SUN CITY
FLORIDA

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

2/1/2017 3:35:24 PM

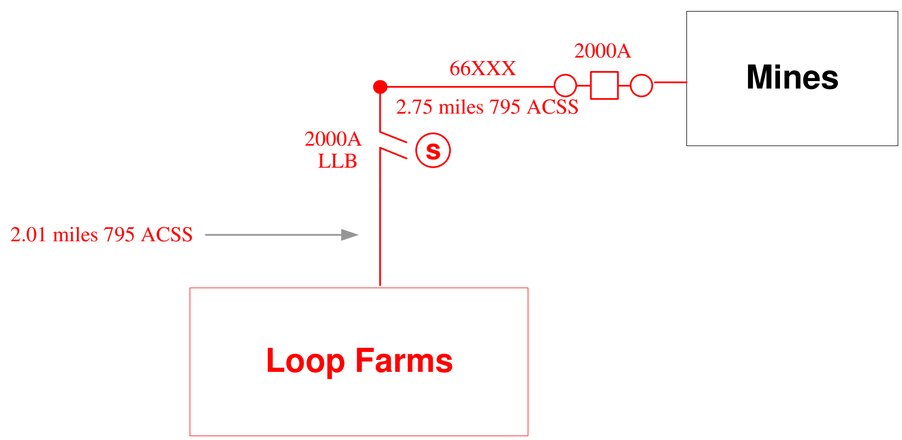



CONSTRAINT MAP
PARCEL NEAR SUN CITY
FLORIDA

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

| | |
|---|---|
| **TITLE:** **Loop Farms Solar Facility** | **2018** |
| **DESCR:** Construct a new 69 kV circuit 66XXX from Mines substation ~ 2.75 miles west to the Loop Farms Tap. Install a 2000A LLB supervisory transmission line switch at the tap point and continue for another 2.01 miles to the Loop Farms Solar Facility. | **IN SVC BY:** **Jun** **See Construction Schedule** |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**



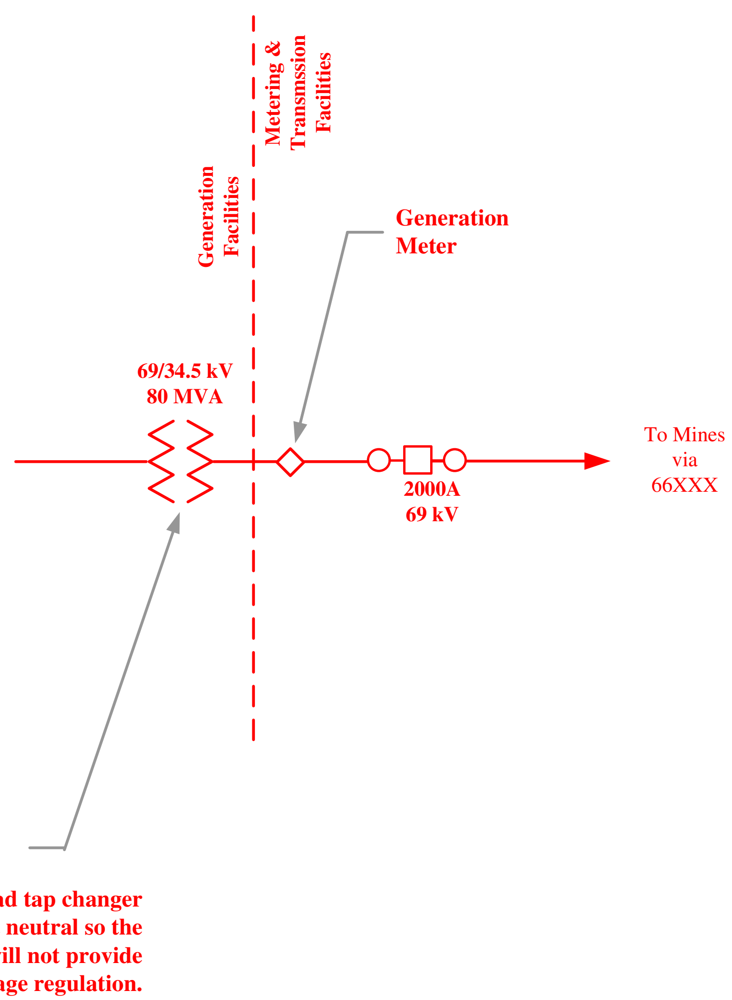

EDCP: SHA

| | | |
|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1963.000** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | **T** |

| TITLE: Loop Farms Solar Facility | 2018 |
|---|---|
| DESCR: Metering station contains a 69/34.5 kV 80 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A kV breaker will also be installed at the station. | IN SVC BY: Jun<br>See Construction Schedule |
| NOTES: Loop Farms Solar Facility will have an expected output of 61 MW | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

## Loop Farms



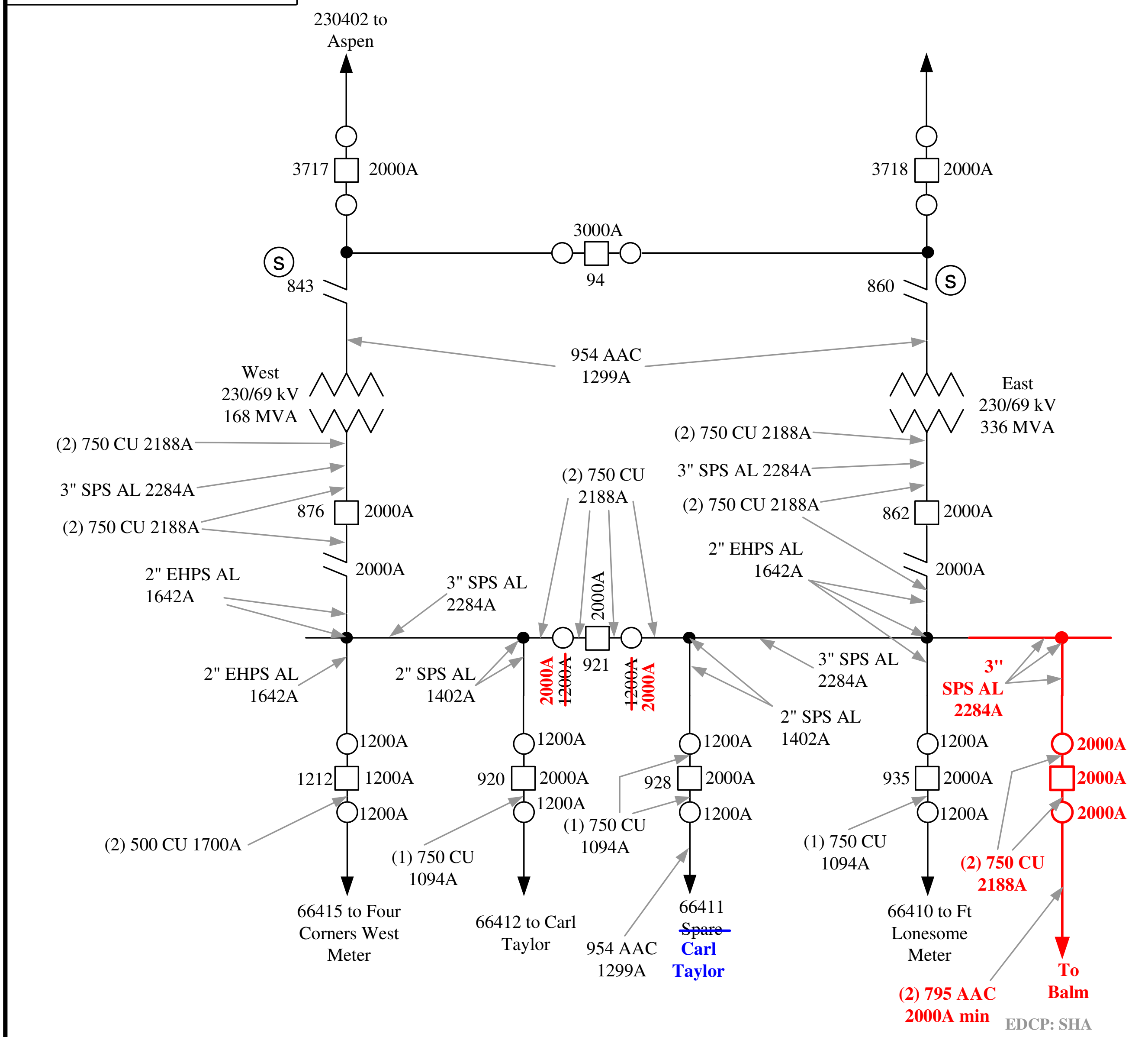

EDCP: SHA

| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | | ESTIMATE #: 1963.000 | S-1 |
|---|---|---|---|---|
| | SUB #: | ISSUE DATE: 04/18/2017 | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | | |

| | |
|---|---|
| **TITLE:** **Loop Farms Solar Facility – Mines Substation** | **2018** |
| **DESCR:** Add a 69 kV, 40kA, 2000A breaker with 2000A disconnects and extend the 69 kV East Bus using 3" SPS AL to accommodate a new circuit to the Loop Farms Solar facility. Upgrade the 1200A disconnects on the 69 kV tie-breaker to 2000A. Install bundled 750 CU for the breaker leads and bundled 795 AAC to connect to the 69 kV circuit | **IN SVC BY:** **Jun** **See Construction Schedule** |
| **NOTES:** Loop Farms will be radially served out of Mines Substation until the ED project to complete the 69 kV path from the Loop Farms tap to the future Balm substation is in-service. | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**
**Blue: Separate Project**

## Mines Substation

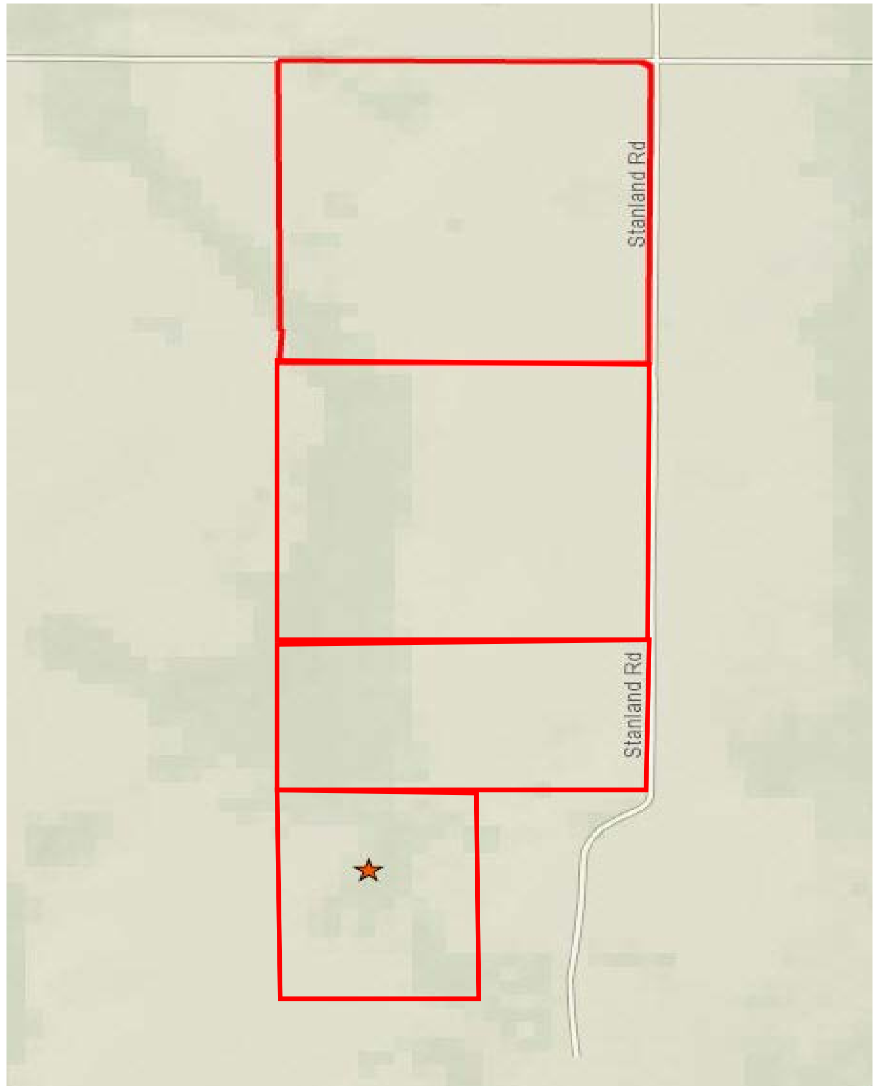



| | | | | |
|---|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | | ESTIMATE #: **1963.000** | **S-2** |
| | SUB #: **266T** | ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | | |

Loop Farms LLC
447± Acres on Stanaland Road
Aerial Photo Showing Topography

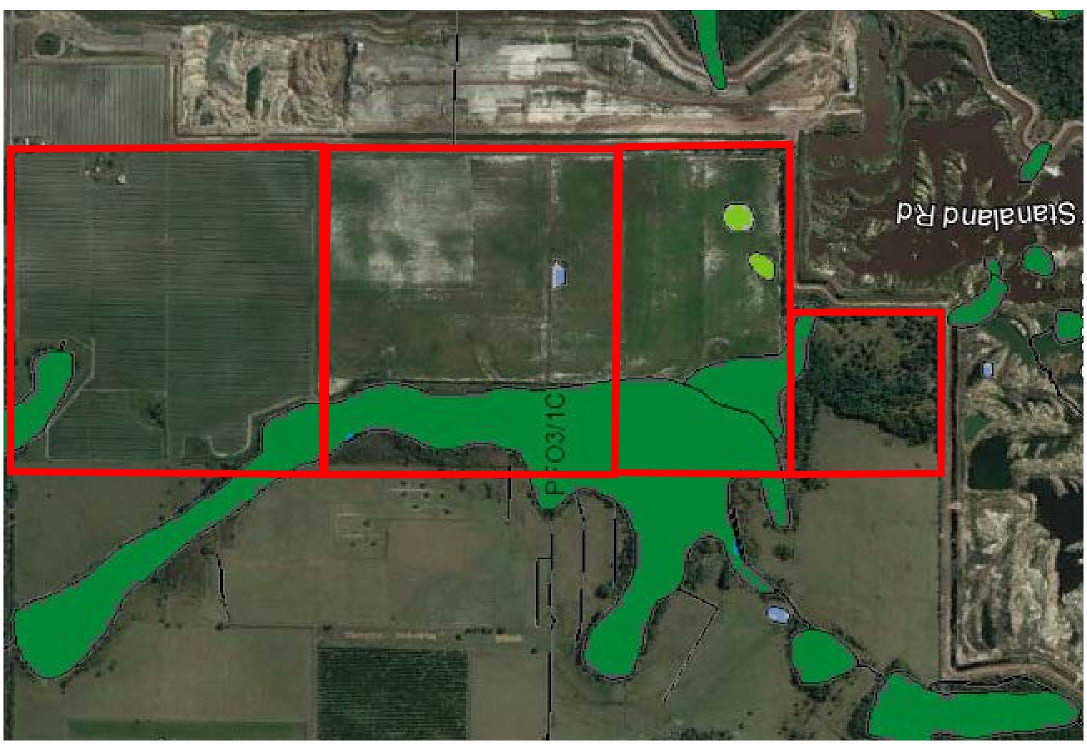

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Loop Farms LLC
447± Acres on Stanaland Road
Existing Land Use - AM



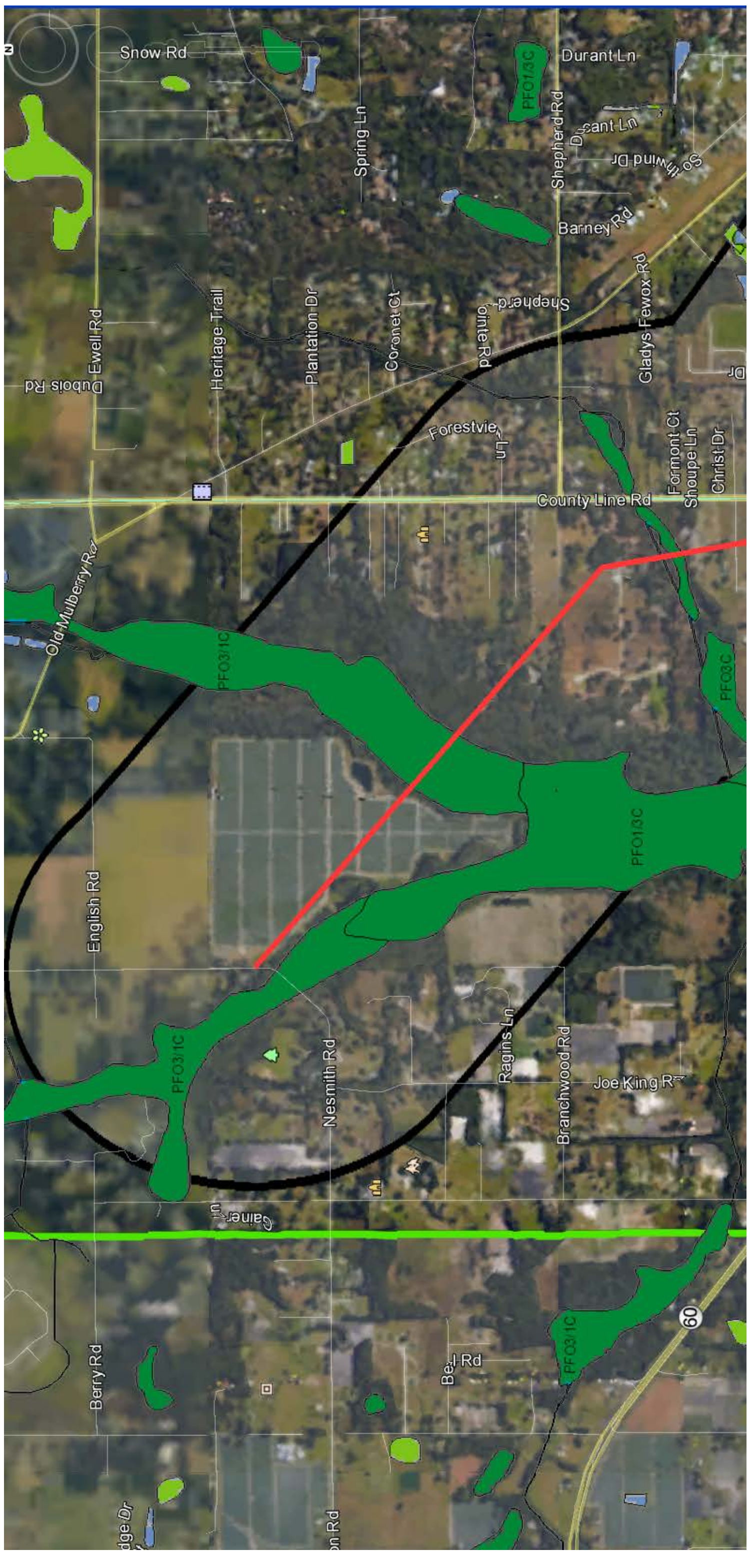

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Loop Farms LLC
447± Acres on Stanaland Road
Potential Wetlands Area



TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)




Potential Wet Areas

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)

| Current Land Use - AS-0.4 | Agricultural SF Estate-1ut per 2.5 ac |
|---|---|

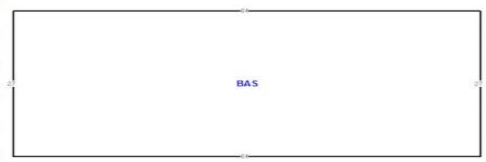
## Building Information

Building 1

| | |
|---|---|
| **Type** | 02 \| MANUFACTURED HOME (AYB > 1976) |
| **Year Built** | 1992 |

Building 1 Construction Details

| Element | Code | Construction Detail |
|---|---|---|
| Class | D | Wood Frame |
| Exterior Wall | 13 | Alum/Vinyl Siding |
| Roof Structure | 3 | Gable or Hip |
| Roof Cover | 1 | Minimum |
| Interior Walls | 5 | Drywall |
| Interior Flooring | 8 | Carpet |
| Heat/AC | 2 | Central |
| Condition | 3 | Average |
| Stories | 1.0 | |
| Bedrooms | 3.0 | |
| Bathrooms | 2.0 | |
| Units | 1.0 | |




Building 1 subarea

| Area Type | Gross Area | Heated Area | Depreciated Value |
|---|---|---|---|
| BAS | 1,728 | 1,728 | $28,873 |
| **Totals** | **1,728** | **1,728** | **$28,873** |

## Extra Features

| OB/XF Code | Description | Building | Year On Roll | Length | Width | Units | Value |
|---|---|---|---|---|---|---|---|
| 0595 | FIREPLACE | 1 | 2002 | 0 | 0 | 1.00 | $1,775 |
| 0470 | OPEN SHED | 0 | 2013 | 0 | 0 | 400.00 | $4,914 |
| 0470 | OPEN SHED | 0 | 2013 | 0 | 0 | 400.00 | $4,914 |
| 0470 | OPEN SHED | 0 | 2013 | 0 | 0 | 600.00 | $7,371 |

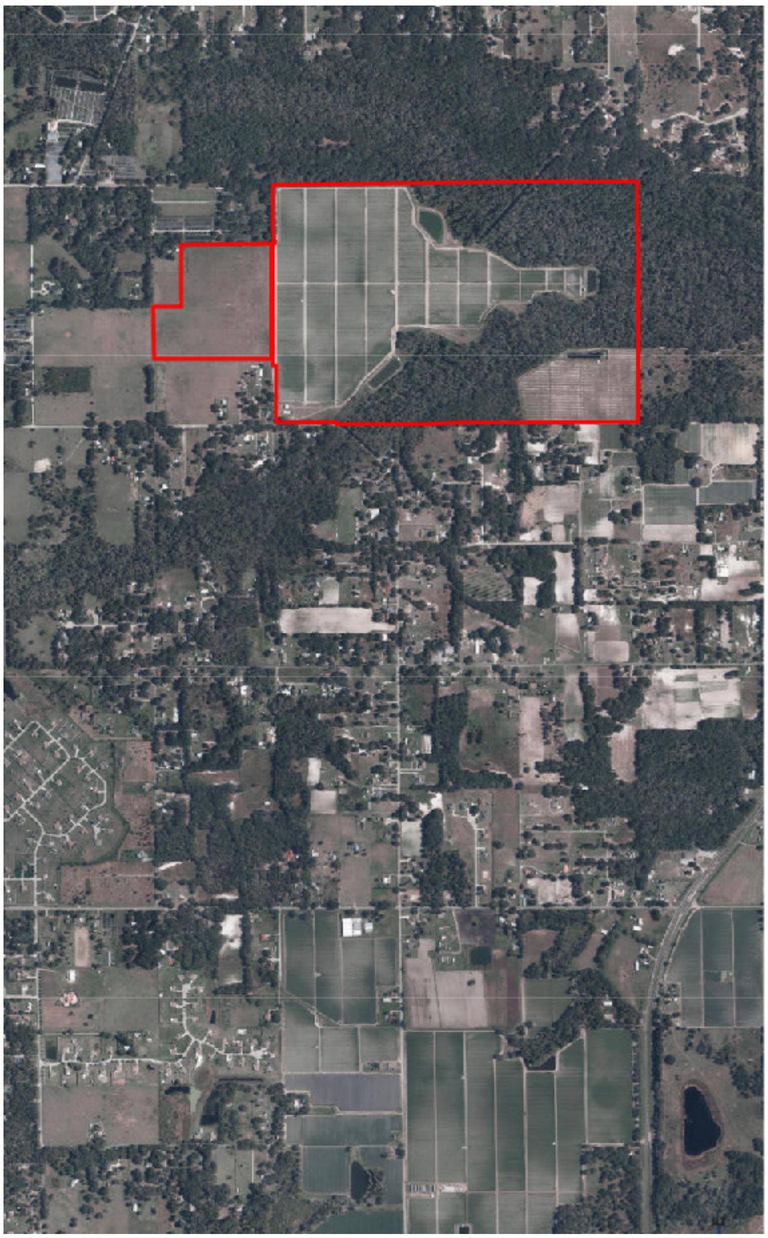
## Land Information - Total Acreage: 243.06

| Use Code | Description | Zone | Front | Depth | Land Type | Total Land Units | Land Value |
|---|---|---|---|---|---|---|---|
| 5110 | STRAWBERRIES | AS-0.4 | 0.0 | 0.0 | AC \| ACREAGE | 139.25 | $375,975 |
| 6630 | SPECIALTY GROVE | AS-0.4 | 0.0 | 0.0 | AC \| ACREAGE | 22.00 | $26,400 |
| 9600 | GB LOWLANDS | AS-0.4 | 0.0 | 0.0 | AC \| ACREAGE | 78.75 | $3,938 |

## Legal Description

S 1/2 OF NW 1/4 AND SW 1/4

4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)



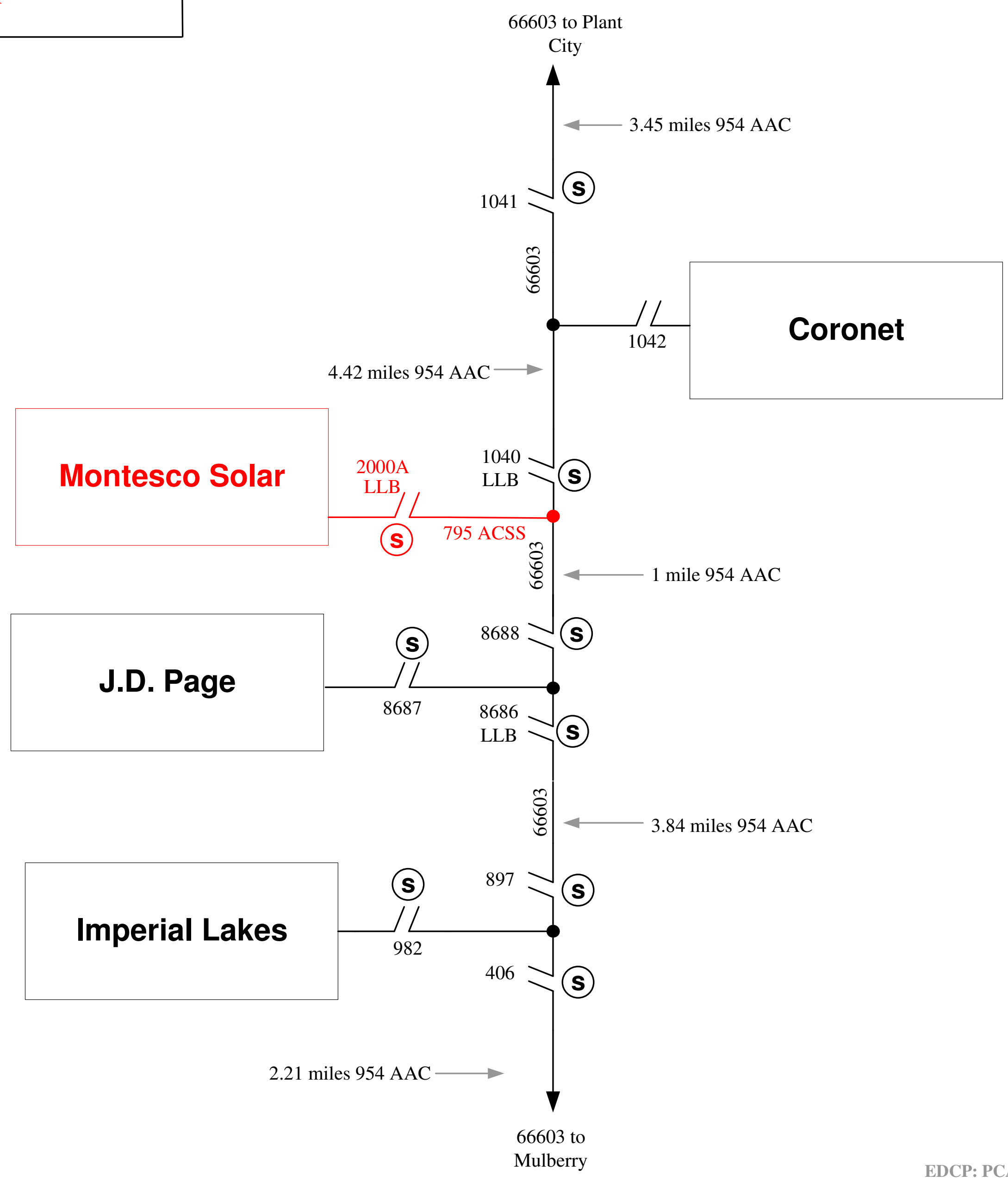
Combined Montesco and Penny Fuller Properties

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

| | |
|---|---|
| **TITLE: Montesco Solar Facility** | **2018** |
| **DESCR:** Tap circuit 66603 to connect to new Meter Station for Montesco Solar Facility<br>Install a 2000A LLB supervisory transmission line switch on Circuit 66603 north of new tap. | **IN SVC BY:**<br>**Jun**<br>**See Construction Schedule** |
| **NOTES:** Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**

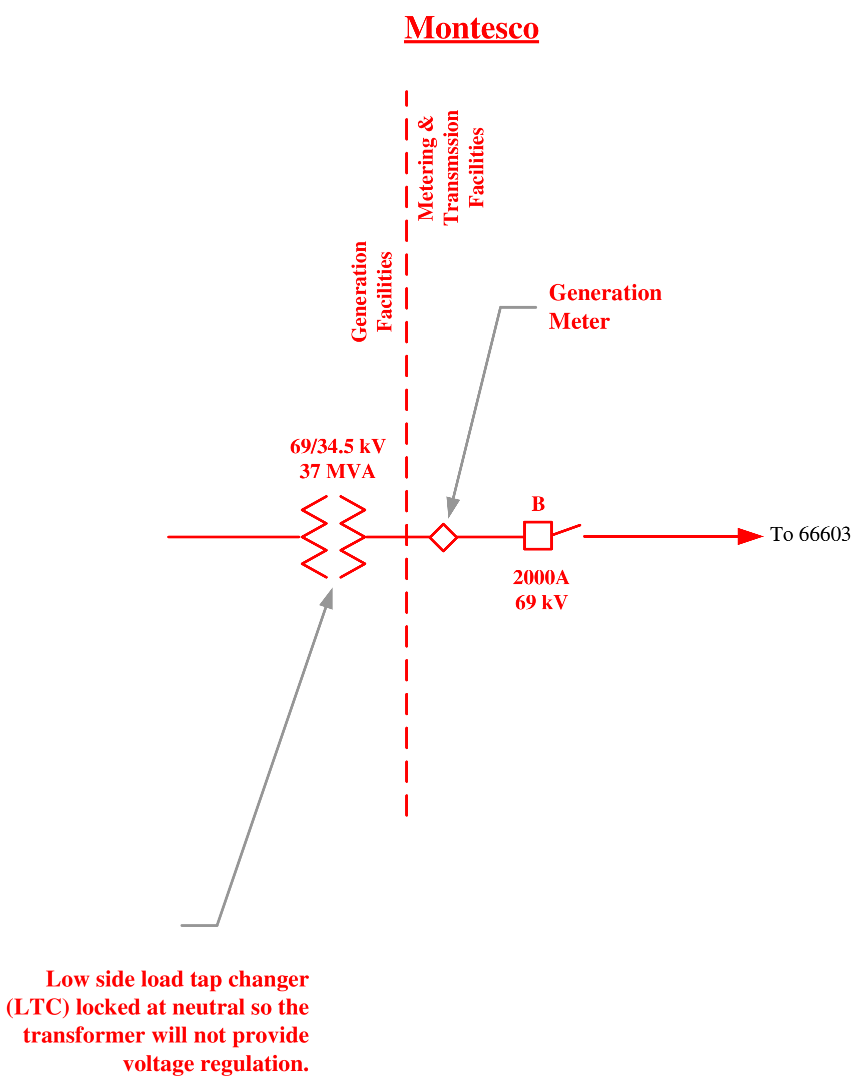



EDCP: PCA

| | | | |
|---|---|---|---|
| TECO TAMPA ELECTRIC AN EMERA COMPANY | IMPROVEMENT: | ESTIMATE #: **1959.000** | **T** |
| | SUB #: ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| | E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | |

| | |
|---|---|
| **TITLE:** **Montesco** | **2018** |
| **DESCR:** Metering station contains a 69/34.5 kV 37 MVA. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station. | **IN SVC BY:** **Jun** See Construction Schedule |
| **NOTES:** Montesco Solar Facility will be tapped off 69 kV circuit 66603 and is expected to have an output of 22 MW with the potential to increase in the future. | N |

Color Specifications:
Black: Existing Construction
**Red: Proposed Construction**




EDCP: PCA

| | | | |
|---|---|---|---|
| IMPROVEMENT: | | ESTIMATE #: **1959.000** | **S** |
| SUB #: | ISSUE DATE: **04/18/2017** | REVISION DATE: | |
| E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM | | | |

# Tampa Electric Company

## 2017 Solar Project Opportunity
## Request for Information (RFI) No. 17-001

RFI Issued:
April 12, 2017

Responses Due:
April 21, 2017 (5:00 p.m. EST)

Tampa Electric Company (Tampa Electric) seeks information from firms qualified and experienced in the development, operation and delivery of utility scale solar projects.

Tampa Electric is primarily interested in utility-scale applications of 10 $MW_{AC}$ to 74.5 $MW_{AC}$ and is also interested in the opportunity that these projects are capable of deploying future battery energy storage. Prospective projects should be constructed on sites that can interconnect directly to Tampa Electric's transmission system, have a minimum operating life of 30 years, and are constructed with tier 1 equipment and in-market warranties. Upon commercial operation, ownership and operation of a project would be transferred to Tampa Electric.

Tampa Electric seeks specific responses to the questions set forth in Exhibit A.

Tampa Electric plans to use the responses to this RFI to help Tampa Electric identify and select one or more full-service developers who can help Tampa Electric reach its solar generation objectives.

Please note that Tampa Electric is undertaking this RFI process based on Tampa Electric's current plans and schedule for projects, all of which are subject to change. By inviting your firm to participate in this RFI process, Tampa Electric is not committing itself to any specific course of action or undertaking. This RFI process may be suspended, modified or terminated by Tampa Electric at any time at its sole discretion.

**CONFIDENTIAL INFORMATION**

This document, together with any related or supporting documents and information provided in connection hereunder, may contain confidential and proprietary information, and shall be considered Confidential Information of Tampa Electric. The reproduction of this RFI or any components thereof by electronic, photographic, xerographic, or other means is authorized solely for the purpose of preparing a response by the intended Respondent. Respondent shall not disclose to anyone, other than its employees, officers, and other authorized parties directly connected to responding to this document, any information concerning or found within this RFI to any third parties.

Unless otherwise agreed by Tampa Electric in writing, responses to this RFI can and may be used by Tampa Electric for any purpose whatsoever including, and not limited to, a future Request For Proposal (RFP). Tampa Electric will not be obligated to protect or treat as confidential any responses provided by a Respondent unless mutually agreed by Tampa Electric and Respondent in a non-disclosure agreement executed by the duly authorized representatives of each party.

No news release, public announcement, or any other reference to this RFI or any project hereunder pertaining to Tampa Electric shall be made without express written consent from Tampa Electric.

**RFI SCHEDULE:**

The tentative schedule for review is as follows:

RFI issued to interested parties: **April 12, 2017**

RFI responses submitted no later than 5 p.m. eastern standard time (EST), **April 21, 2017**

RFI evaluation completed and shortlist of Respondents notified **April 28, 2017**

Tampa Electric reserves the right to modify this schedule or to close this RFI at any time in its sole discretion.

**RFI SUBMITTAL PROCESS**

Respondents must submit their response(s) electronically by the aforementioned deadline to jlriendeau@tecoenergy.com**.** All submittals should be titled "2017 Solar Project Opportunity: [insert company name]."

**DISCLAIMERS**

Tampa Electric reserves the right, without qualification and in its sole discretion to: (i) select or reject any or all proposals, offers, or responses; (ii) waive any formality, technicality, requirement, or irregularity in any proposals received; (iii) discuss with any Respondent the details of any response submitted by a Respondent in order to fully evaluate the response; (iv) negotiate the terms of any proposal with any Respondent without seeking new or amended proposals from any other party; (v) decline to enter into any agreement with any Respondent for any reason or no reason at all; and (vi) close or terminate this RFI in whole or in part at any time.

All costs incurred by a Respondent in connection with the preparation and submission of a response, proposal and/or any subsequent negotiations in connection with this RFI shall be borne solely by the Respondent. Tampa Electric will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFI process proceeds to a successful conclusion or is abandoned by Tampa Electric in its sole discretion.

**ABOUT TAMPA ELECTRIC**

Tampa Electric Company is a regulated electric utility serving over 725,000 customers in the greater Tampa Bay area. Tampa Electric is a subsidiary of Emera Inc., a geographically diverse energy and services company headquartered in Halifax, Nova Scotia, Canada. The company invests in electricity generation, transmission and distribution, as well as gas transmission and utility energy services with a strategic focus on transformation from high carbon to low carbon energy sources. Emera has investments throughout North America and in four Caribbean countries.

**EXHIBIT A**

**FULL SERVICE DEVELOPMENT, REQUEST FOR INFORMATION**

I. Please list and describe the services your company provides that are self-performed including, but not limited to: land procurement, environmental assessment and permitting, engineering and design, electrical, project financing, regulatory support, engineering construction and procurement. Please limit this description to in-house capabilities, not services that the Respondent would contract. ***Limit response to three (3) pages.***

II. Please provide a description of any self-performed operation, monitoring and maintenance (O&M) services your company offers along with the corresponding pricing. Detail the number and size of the solar stations that you currently provide O&M services for. ***Limit response to two (2) pages.***

III. Please describe your company's ability to post performance bonds or other forms of project security.

IV. Please provide the last three (3) years of your company's audited financials.

V. Please list North American PV solar projects 10 $MW_{AC}$ and greater that your company provided full development services and constructed or provided construction management during the last two (2) years. Specifically list the services performed. ***Limit response to two (2) pages.***

VI. Please provide solar development and construction experience in Florida. ***Limit response to two (2) pages.***

VII. Please describe your company's approach and ability for managing four (4) simultaneous utility-scale projects that are located within a 30-mile radius. Include your company's project development and construction philosophy. Assume each project is 50 $MW_{AC}$. Provide an overall project schedule that includes site evaluation, development, engineering, permitting, procurement and construction. ***Limit response to four (4) pages.***

VIII. Is your company willing to develop and construct a project on land owned by Tampa Electric?

IX. Does your company own or have the right to develop any sites within the Tampa Electric service area that could produce $10MW_{AC}$ or greater of photovoltaic (PV) solar energy, and that could be transferred to Tampa Electric upon commercial operation?

A. Please describe the property, including its location and size, and how the property is controlled and if any due diligence has been performed.

B. Solar Project General Description

1. Please provide a site boundary aerial map identifying the exact geographic location of the proposed facility, if known, or a general area under consideration for development.

2. Please provide the following information about the project:

a) Nameplate capacity ($MW_{DC}/MW_{AC}$)
b) Contract price ($\$/kW_{AC}$)
c) Energy price ($/MWh)
d) Expected annual gross generation (MWh)
e) Expected annual capacity factor (%)
f) Fixed and expected variable operation and maintenance ($/MW)
g) Expected system degradation (%/yr)

Note: Respondent proposed projects should include complete energy modeling results including 8760 hourly energy projections with their submissions; $PV_{SYST}$ is the preferred model but alternative models are acceptable. Model assumptions and inputs should be included with the energy results.

3. Please provide a detailed description of the solar project:

   a) Proposed panel technology model and type
   b) Project interconnection point and voltage (kV)
   c) Identification of major equipment suppliers and description of manufacturers' and vendors' warranties, if known.
   d) Details regarding the design/service life of the project.
   e) Anticipated project construction time and anticipated construction milestone schedule
   f) Examples of similar systems in existence elsewhere in the world

4. Please describe the proposed project team and project financing structure:

   a) Team members
   b) Team members' experience with similar projects
   c) Team members' experience in FRCC, SERC, OR NERC
   d) Potential financing through construction

5. Please describe the proposed network and control scheme:

   a) SCADA system and communications equipment

6. Please describe any environmental, safety, and health issues related to the project:

   a) Safety concerns related to the project (if any)
   b) Physical dimensions of major equipment
   c) Land area required
   d) Relevant geographic restrictions or requirements
   e) Noise, visual or any negative community impact generated by equipment
   f) Water consumption

7. Please provide the all-in-cost up to the designated point of delivery (including land and step up transformer). The project cost should be presented in terms of an all-in-cost ($/kW$_{AC}$) and the levelized cost of energy produced (LCOE) based upon a 30-year life.

8. Please provide a project schedule, including permitting, with the shortest duration in which the project can be completed.

9. Please provide a conceptual summary outlining the following commercial terms:

   a) Proposed legal structure for construction and transfer of project (e.g., build, own and transfer).
   b) Equipment warranties
   c) Performance guarantees for output and availability

**6.** Has TECO acquired any land or land rights associated with the various SoBRA Tranches? If yes, please provide details of the acquisition(s) and associated documentation.

**A.** Yes. Tampa Electric employed a screening and due diligence process to select its solar sites. Each project site was evaluated and selected after considering environmental assessments, size of the project sites, proximity to Tampa Electric transmission facilities, cost of land, and suitability of the sites for solar PV construction.

Tampa Electric has purchased land for the two projects in tranche one and one site in tranche two. The sites that have been purchased for tranche one are Payne Creek Solar and Balm Solar. Grange Hall Solar, a tranche two project, has also been purchased.

The remaining sites planned for tranches two through four are under contract and controlled by Tampa Electric. Tampa Electric plans to purchase the remaining sites for tranche two by the end of 2017. Tranche three and four projects will be purchased in 2018.

The ten sites planned for Tampa Electric's 600 MW of PV solar projects total more than 4,500 acres and are located throughout Tampa Electric's service area.

**7.** Does TECO believe that joint ownership is feasible for any of the various SoBRA Tranches?

**A.** Possibly; however, multi-party ownership introduces complexity and additional costs in establishing ownership provisions and overseeing operational controls. Additionally, it could result in an adverse impact on cost-effectiveness and the company's ability to control its committed cost cap.

**8**. Has TECO explored any joint ownership options for acquiring Solar PV capacity? If yes, please explain in detail.

**A.** Yes, Tampa Electric has been contacted by numerous solar PV developers over the last several years. In these meetings, multiple options have been discussed including joint ownership. During those discussions the developers were asked but have not offered a binding letter of intent or other commitment that meets the cost effectiveness and timing of 2018-2021 for Tampa Electric's proposed ten projects totaling 600 MW.

**9.** In Paragraph 6(c) of the proposed Settlement Agreement, it states “A SoBRA Tranche may consist of a single project or include multiple individual solar projects, which may be located throughout the Company’s retail service territory.” Is this language intended to limit the Company to only pursuing options that are located within its retail service territory? If so, why?

**A.** No. However, any solar projects built outside the company’s service area would be subject to incremental transmission or wheeling charges that would likely make them less cost-effective than those built within the company’s service area. Paragraph 6(c) is a Negotiated Term and is intended to emphasize that the SoBRA projects would be constructed for the benefit of the company’s retail customers.

**10.** Please provide a breakdown of estimated operating costs associated with the various SoBRA Tranches to be included in base rate revenue requirements.

**A.** Tampa Electric estimates operating costs to be $7/kw-yr and that they will be escalated annually by 2.5% during the Term. This includes operations and monitoring, performance engineering, maintenance, warranty administration, spare parts inventory and vegetation management.

**11.** Refer to Paragraph 6(d), which addresses the debt rate utilized to calculate the revenue requirements associated with the SoBRA projects.

a. Please explain exactly what the Company defines as "prospective long-term debt issuances."

b. Does this reflect a projected cost rate or an actual cost rate?

c. Please explain how the incremental cost rate for long-term debt will be calculated.

**A.** a. Paragraph 6(d) is a Negotiated Term intended to specify that the company will use the cost rate for long term debt that is issued to fund the solar projects to calculate the revenue requirement associated with a SoBRA. This is different from the cost rate of the company's embedded overall long-term debt as reported on its surveillance reports. By using the incremental rate, the first-year revenue requirement will reflect the additional cost of the solar project.

b. The company intends to use actual cost rates that reflect the company's most recent issuances of long term debt for purposes of calculating the revenue requirement for the solar projects.

c. See answer to b, above.

**12.** Refer to Paragraph 6(l) on page 18, which addresses the investment tax credits on a normalized basis associated with the SoBRA projects.

a. Please explain how the investment tax credits will be adjusted on a normalized basis.

b. What cost rate will be used for the investment tax credits?

c. What capital components (common equity, long-term debt, and short-term debt) will be included in the calculation of the cost rate for the investment tax credits?

**A.** a. The Agreement also allows the company to take advantage of the existing 30% solar investment tax credit for the benefit of customers while the credit remains in effect. Paragraph 6(l) is a Negotiated Term intended to ensure that the capital structure will be "adjusted" to include the investment tax credits consistent with tax normalization rules. The amount of the investment tax credits included in the capital structure will not be adjusted.

b. Consistent with tax normalization rules, the investment tax credits will be assigned a weighted cost rate based on the incremental equity and debt components that would have otherwise been used to fund the solar project.

c. See answer to b, above.

**13.** Please provide a resource plan that includes the solar projects and one without the solar projects for the term of the settlement. For each unit identified, please provide all features of the unit including but not limited to: MW, installed cost/MW, Fuel Type and Unit Type.

**A.** The solar projects planned for recovery under the SoBRA mechanism are a continuation of Tampa Electric's long-standing commitment to clean energy. The company's strategy to reduce its carbon footprint started in 1999 with the repowering of the former Gannon Station to natural gas-fired Bayside Power Station, and most recently included the expansion of the Polk Power Station's combined cycle generation. This strategy will reduce the company's exposure to financial and other risks associated with burning carbon-based fuels, and because the fuel cost of solar generation is zero, will provide an important measure of price stability to customers.

Using the SoBRA mechanism, the company plans to install over 6 million solar panels into various projects in its service territory. These projects and the SoBRA mechanism will allow the company to transition power generation to less carbon intensity while keeping prices for electricity affordable for its customers. When the projects are complete, about 6 percent of Tampa Electric's energy will come from the sun.

The requested resource plans are summarized in the tables below.

**2017 TYSP No Solar**

| Year | Portfolio Additions | MW W in / Sum | Installed Cost / MW | Fuel Type | Unit Type |
|---|---|---|---|---|---|
| **2018** | - | - | - | - | - |
| **2019** | - | - | - | - | - |
| **2020** | - | - | - | - | - |
| **2021** | (1) GE 7FA.05 | 2 20 / 204 | 700,040 | Gas | Combustion Turbine |
| **2022** | - | - | - | - | - |

**600 M W of Solar**

| Year | Portfolio Additions | MW W in / Sum | Installed Cost / MW | Fuel Type | Unit Type |
|---|---|---|---|---|---|
| **2018** | Solar Phase 1 | 0 / 150 | 1,396,000 | Solar | PV |
| **2019** | Solar Phase 2 | 0 / 250 | 1,443,000 | Solar | PV |
| **2020** | Solar Phase 3 | 0 / 150 | 1,437,000 | Solar | PV |
| **2021** | Solar Phase 4 | 0 / 50 | 1,477,000 | Solar | PV |
| **2022** | - | - | - | - | - |

**14.** Please refer to Paragraph 6(b). Please provide an estimate of both the Incremental Annualized SoBRA Revenue Requirements and Cumulative Annualized SoBRA Revenue Requirements when using a $1,475kWac cost cap assuming full capacity buildout and 2% variance.

**A.** See table below.

| Year | Earliest Rate Change And In-Service Date | Maximum Incremental SoBRA MW | Maximum Incremental Annualized SoBRA Revenue Requirements (millions) | Maximum Cumulative SoBRA MW | Maximum Cumulative Annualized SoBRA Revenue Requirements (millions) |
|---|---|---|---|---|---|
| **2018** | September 1 | 150 | $28.3* | 150 | $28.3 |
| **2019** | January 1 | 250 | $47.2 | 400 | $75.4 |
| **2020** | January 1 | 150 | $28.6 | 550 | $104.0 |
| **2021** | January 1 | 50 | $9.8 | 600 | $113.9 |

*Note:*
**The annual revenue requirement is approximately $28.3 million, however, since the first 150 MW phase is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $9.4 million.*

**15.** Please refer to Paragraph 6(c).

a. Please explain whether TECO could buy an existing in-service solar farm and meet the terms of the settlement.

b. If so, please explain if this existing in-service solar farm would be subject to the $1,500kWac cost cap.

c. If not, would additional construction on an existing in-service solar farm satisfy the terms of the settlement and would that site then be subject to the $1,500kWac cost cap?

**A.** a. Paragraph 6(c) is a Negotiated Term. It contains this language: "Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above." Based on this language, and as discussed in its answer to data request No. 6, above, the company has made plans to construct 600 MW of solar as set forth in the table. Additionally, the company is not aware of any large scale solar farms in existence within its retail service area.

b. N/A

c. The company is not aware of any existing non-company owned solar farms within its retail service area. If a site was available and land could be used to build company-owned solar, the newly constructed solar would be subject to the $1,500 / kWac cost cap.

**16.** Please refer to Paragraph 6(m).

a. Please provide the estimated rate impact annually of the solar projects for a 1000/kwh-mo residential customer using the $1,500 kWac cost cap.

b. Please provide the same rate impact when using a $1,475 kWac cost.

**A.** a. See table below.

**Tampa Electric Residential Bill Comparison**
**SoBRA Settlement Impacts at $1500/kW**
**1,000 kWh Monthly Bill**

| *Annual Change* | Jan-Aug '18 | Sep-Dec '18 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Base Energy Charge** | - | 2.13 | 2.97 | 1.80 | 0.62 |
| **Fuel Cost Recovery** | (0.23) | - | (1.62) | (0.69) | (0.23) |
| **Gross Receipts Tax** | (0.01) | 0.06 | 0.03 | 0.03 | 0.01 |
| **Total** | $(0.24) | $2.19 | $1.38 | $1.14 | $0.40 |

| *Cumulative Change* | Jan-Aug '18 | Sep-Dec '18 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Base Energy Charge** | - | 2.13 | 5.10 | 6.90 | 7.52 |
| **Fuel Cost Recovery** | (0.23) | (0.23) | (1.85) | (2.54) | (2.77) |
| **Gross Receipts Tax** | (0.01) | 0.05 | 0.08 | 0.11 | 0.12 |
| **Total** | $(0.24) | $1.95 | $3.33 | $4.47 | $4.87 |
| *Note:*<br>**Compared to 2017 Approved Rates. Impacts of SoBRA Settlement Changes Only.* | | | | | |

b. See table below.

**Tampa Electric Residential Bill Comparison**
**SoBRA Settlement Impacts at $1475/kW**
**1,000 kWh Monthly Bill**

| *Annual Change* | Jan-Aug '18 | Sep-Dec '18 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Base Energy Charge** | - | 2.09 | 2.93 | 1.77 | 0.61 |
| **Fuel Cost Recovery** | (0.23) | - | (1.62) | (0.69) | (0.23) |
| **Gross Receipts Tax** | (0.01) | 0.06 | 0.03 | 0.03 | 0.01 |
| **Total** | $(0.24) | $2.15 | $1.34 | $1.11 | $0.39 |

| *Cumulative Change* | Jan-Aug '18 | Sep-Dec '18 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Base Energy Charge** | - | 2.09 | 5.02 | 6.79 | 7.40 |
| **Fuel Cost Recovery** | (0.23) | (0.23) | (1.85) | (2.54) | (2.77) |
| **Gross Receipts Tax** | (0.01) | 0.05 | 0.08 | 0.11 | 0.12 |
| **Total** | $(0.24) | $1.91 | $3.25 | $4.36 | $4.75 |
| | | | | | |
| *Note:* *Compared to 2017 Approved Rates. Impacts of SoBRA Settlement Changes Only.* | | | | | |

**17.** For all planned solar generation, please detail the depreciation life and actual life of each individual unit if available.

**A.** The average service life applied to the SoBRA generation assets is 30 years consistent with FPSC Order No. PSC-2015-0573-PAA-EI.

**18.** Please refer to Paragraph 6(j).

a. If TECO does not construct the Maximum Incremental SoBRA MW in one year of the settlement term, can the construction be completed in another year and cost recovery still be available for TECO? For example, if TECO were to not construct any approved solar tranches in 2020, could TECO construct the 2020 unused capacity in 2021 and still recover cost? Please explain.

b. If so, would these costs be limited to the Maximum Incremental Annualized SoBRA Revenue Requirements, the Maximum Cumulative Annualized SoBRA Revenue Requirements mentioned in Paragraph 6(b), or both.

**A.** a. Yes. Paragraph 6(j) is a Negotiated Term intended to specify that if the company does not construct the available 150 MW of SoBRA generation in 2020 per the example provided it would be able to carryover the 150 MW into 2021. However, the company will not be able to secure cost recovery via the SoBRA mechanism for more than 600 MW.

b. Yes. Paragraph 6(b) is a Negotiated Term intended to specify the maximum annualized and cumulative revenue requirement amounts available under the SoBRA mechanism.

**19.** Please refer to Paragraph 6(c).

a. Please explain the relationship between a 2% variance in revenue requirements and a 5 MW variance for 2019 SoBRA Tranche.

b. Please explain if the 2% and 5 MW variance only applies to 2018 and 2019 SoBRA Tranches.

c. Please explain if the 2% variance applies to the $1,500kWac cost cap as well.

**A.** a. Paragraph 6(c) is a Negotiated Term intended to specify that the two percent variance only applies to the 250 MW for the 2019 SoBRA tranche. This means, for example, that the company could construct 255 MW of solar projects in 2019 to accommodate efficient planning and construction of its planned solar projects. It is expected that a two percent increase in MW would translate to a two percent increase in revenue requirements.

b. The two percent variance only applies to the 2019 SoBRA tranche.

c. The two percent variance does not apply to the $1,500 / KWac cost cap.

**20.** Referring to Paragraph 6(i)(i) of the settlement, please explain the basis for only allocating 40 percent of the revenue requirement to the lighting class.

**A.** As with all the other elements of the 2017 Agreement, Paragraph 6(i)(i) is a Negotiated Term. The 40 percent is not a calculated amount, but rather, was settled on to reflect that the fuel benefit of the solar tranches will be included in the calculation of lighting fuel rates and reflects a negotiation position that 40% is a reasonable allocation of the revenue requirements of the solar.

**21.** Referring to Paragraph 6(i)(ii) of the settlement, please discuss the impact on low- vs high-load factor demand customers resulting from the proposed SOBRA increases to demand charges.

**A.** The attached chart in MFR Schedule A2 format shows a typical bill for Tampa Electric's GSD customers at 600 MW of SOBRA buildout. The impact of SOBRA is two-fold: the increased base revenue requirement is recovered from the demand charge and the reduced fuel cost is recovered through the fuel energy charge. As can be seen in column 18, for a demand billed customer the impact is lower at higher load factors.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-ei
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

SCHEDULE A-2 FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS

FLORIDA PUBLIC SERVICE COMMISSION EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

## GSD - GENERAL SERVICE DEMAND

| | RATE SCHEDULE GSD | | BILL UNDER PRESENT RATES | | | | | | | BILL UNDER PROPOSED RATES | | | | | | | INCREASE | | COSTS IN CENTS/KWH | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| Line | TYPICAL | | BASE | FUEL | ECCR | CAPACITY | ECRC | GRT | TOTAL | BASE | FUEL | ECCR | CAPACITY | ECRC | GRT | TOTAL | DOLLARS | PERCENT | PRESENT | PROPOSED |
| No. | KW | KWH | RATE | CHARGE | CHARGE | CHARGE | CHARGE | CHARGE | | RATE | CHARGE | CHARGE | CHARGE | CHARGE | CHARGE | | (16)-(9) | (17)/(9) | (9)/(2)*100 | (16)/(2)*100 |
| 1 | 75 | 10,950 | $ 762.51 | $ 323.68 | $ 19.71 | $ 6.90 | $ 42.27 | $ 29.62 | $ 1,184.68 | $ 856.57 | $ 293.35 | $ 20.59 | $ 6.90 | $ 42.27 | $ 31.27 | $ 1,250.95 | $ 66.26 | 5.6% | 10.82 | 11.42 |
| 2 | 75 | 19,163 | $ 1,138.10 | $ 566.44 | $ 57.75 | $ 20.25 | $ 73.97 | $ 47.60 | $ 1,904.11 | $ 1,300.85 | $ 513.36 | $ 60.75 | $ 20.25 | $ 73.97 | $ 50.49 | $ 2,019.67 | $ 115.56 | 6.1% | 9.94 | 10.54 |
| 3 | 75 | 32,850 | $ 1,378.18 | $ 971.05 | $ 57.75 | $ 20.25 | $ 126.80 | $ 65.49 | $ 2,619.51 | $ 1,540.93 | $ 880.05 | $ 60.75 | $ 20.25 | $ 126.80 | $ 67.40 | $ 2,696.19 | $ 76.67 | 2.9% | 7.97 | 8.21 |
| 4 | 75 | 49,275 | $ 1,620.78 | $ 1,448.81 | $ 57.75 | $ 20.25 | $ 190.20 | $ 85.58 | $ 3,423.37 | $ 1,781.70 | $ 1,313.30 | $ 60.75 | $ 20.25 | $ 190.20 | $ 86.31 | $ 3,452.52 | $ 29.15 | 0.9% | 6.95 | 7.01 |
| 5 | | | | | | | | | | | | | | | | | | | | |
| 6 | 500 | 73,000 | $ 4,895.04 | $ 2,157.88 | $ 131.40 | $ 45.99 | $ 281.78 | $ 192.62 | $ 7,704.71 | $ 5,522.11 | $ 1,955.67 | $ 137.24 | $ 45.99 | $ 281.78 | $ 203.66 | $ 8,146.45 | $ 441.74 | 5.7% | 10.55 | 11.16 |
| 7 | 500 | 127,750 | $ 7,398.98 | $ 3,776.29 | $ 385.00 | $ 135.00 | $ 493.12 | $ 312.52 | $ 12,500.90 | $ 8,483.98 | $ 3,422.42 | $ 405.00 | $ 135.00 | $ 493.12 | $ 331.78 | $ 13,271.29 | $ 770.39 | 6.2% | 9.79 | 10.39 |
| 8 | 500 | 219,000 | $ 8,999.50 | $ 6,473.64 | $ 385.00 | $ 135.00 | $ 845.34 | $ 431.76 | $ 17,270.24 | $ 10,084.50 | $ 5,867.01 | $ 405.00 | $ 135.00 | $ 845.34 | $ 444.53 | $ 17,781.38 | $ 511.15 | 3.0% | 7.89 | 8.12 |
| 9 | 500 | 328,500 | $ 10,616.81 | $ 9,658.72 | $ 385.00 | $ 135.00 | $ 1,268.01 | $ 565.73 | $ 22,629.27 | $ 11,689.66 | $ 8,755.35 | $ 405.00 | $ 135.00 | $ 1,268.01 | $ 570.59 | $ 22,823.61 | $ 194.33 | 0.9% | 6.89 | 6.95 |
| 10 | | | | | | | | | | | | | | | | | | | | |
| 11 | 2000 | 292,000 | $ 19,480.44 | $ 8,631.52 | $ 525.60 | $ 183.96 | $ 1,127.12 | $ 767.91 | $ 30,716.55 | $ 21,988.72 | $ 7,822.68 | $ 548.96 | $ 183.96 | $ 1,127.12 | $ 812.09 | $ 32,483.53 | $ 1,766.97 | 5.8% | 10.52 | 11.12 |
| 12 | 2000 | 511,000 | $ 29,496.18 | $ 15,105.16 | $ 1,540.00 | $ 540.00 | $ 1,972.46 | $ 1,247.53 | $ 49,901.33 | $ 33,836.18 | $ 13,689.69 | $ 1,620.00 | $ 540.00 | $ 1,972.46 | $ 1,324.57 | $ 52,982.90 | $ 3,081.57 | 6.2% | 9.77 | 10.37 |
| 13 | 2000 | 876,000 | $ 35,898.28 | $ 25,894.56 | $ 1,540.00 | $ 540.00 | $ 3,381.36 | $ 1,724.46 | $ 68,978.66 | $ 40,238.28 | $ 23,468.04 | $ 1,620.00 | $ 540.00 | $ 3,381.36 | $ 1,775.58 | $ 71,023.26 | $ 2,044.59 | 3.0% | 7.87 | 8.11 |
| 14 | 2000 | 1,314,000 | $ 42,367.52 | $ 38,634.89 | $ 1,540.00 | $ 540.00 | $ 5,072.04 | $ 2,260.37 | $ 90,414.81 | $ 46,658.92 | $ 35,021.39 | $ 1,620.00 | $ 540.00 | $ 5,072.04 | $ 2,279.80 | $ 91,192.15 | $ 777.33 | 0.9% | 6.88 | 6.94 |
| 15 | | | | | | | | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | | | | | | | | |

| Line | | PRESENT | | | | | | PROPOSED | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | | GSD | GSDT | | GSD OPT. | | | GSD | GSDT | | GSD OPT. | |
| 19 | CUSTOMER CHARGE | 33.24 | 33.24 | $/Bill | 33.24 | $/Bill | | 33.24 | 33.24 | | 33.24 | $/Bill |
| 20 | DEMAND CHARGE | 10.25 | - | $/KW | - | $/KW | | 12.42 | - | $/KW | - | $/KW |
| 21 | BILLING | - | 3.46 | $/KW | - | $/KW | | - | 4.19 | $/KW | - | $/KW |
| 22 | PEAK | - | 6.79 | $/KW | - | $/KW | | - | 8.22 | $/KW | - | $/KW |
| 23 | ENERGY CHARGE | 1.754 | - | ¢/KWH | 6.660 | ¢/KWH | | 1.754 | - | ¢/KWH | 7.519 | ¢/KWH |
| 24 | ON-PEAK | - | 3.211 | ¢/KWH | - | ¢/KWH | | - | 3.211 | ¢/KWH | - | ¢/KWH |
| 25 | OFF-PEAK | - | 1.159 | ¢/KWH | - | ¢/KWH | | - | 1.159 | ¢/KWH | - | ¢/KWH |
| 26 | FUEL CHARGE | 2.956 | - | ¢/KWH | 2.956 | ¢/KWH | | 2.679 | - | ¢/KWH | 2.679 | ¢/KWH |
| 27 | ON-PEAK | | 3.166 | ¢/KWH | - | ¢/KWH | | | 2.870 | ¢/KWH | - | ¢/KWH |
| 28 | OFF-PEAK | | 2.865 | ¢/KWH | - | ¢/KWH | | | 2.597 | ¢/KWH | - | ¢/KWH |
| 29 | CONSERVATION CHARGE | 0.77 | 0.77 | $/KW | 0.180 | ¢/KWH | | 0.81 | 0.81 | $/KW | 0.188 | ¢/KWH |
| 30 | CAPACITY CHARGE | 0.27 | 0.27 | $/KW | 0.063 | ¢/KWH | | 0.27 | 0.27 | $/KW | 0.063 | ¢/KWH |
| 31 | ENVIRONMENTAL CHARGE | 0.386 | 0.386 | ¢/KWH | 0.386 | ¢/KWH | | 0.386 | 0.386 | ¢/KWH | 0.386 | ¢/KWH |

Notes:

A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).

B. Charges at 20% LF are based on the GSD Option rate; 35% and 60% LF charges are based on the standard rate; and 90% LF charges are based on the TOD rate.

C. All calculations assume meter and service at secondary voltage.

D. TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.

E. Cost recovery clause factors are the current 2017 factors.

Supporting Schedules: E-13c, E-14 Supplement

Recap Schedules:

**22.** Please refer to Paragraph 8(b).

a. Please provide all the information and company's plan, known at this stage, regarding the expected retirements of the coal-fired generating assets or other assets of the magnitude that would ordinarily or otherwise require a capital recovery schedule.

b. When does the company expect to begin the retirement of its AMR meters, and how many years does TECO expect it will require to complete the AMR- to- AMI meter replacement?

c. What is the expected unrecovered net investment amount, in dollars, associated with the AMR meter retirement each year during the term of the 2017 Amended and Restated Stipulation and Settlement Agreement?

d. What will be the estimated percentage of the total investment booked to depreciation Account 37000 – Meters that is expected to be affected by the AMR to AMI meter replacement each year for the period of 2017 - 2021?

e. In reference to Rule 25-6.0436(7)(a), F.A.C., and the following excerpt of the Commission's previous order regarding the timely establishment of capital recovery schedules cited below[1], please explain how the approach of deferring the establishment of the capital recovery schedules described in Paragraph 8(b) would benefit TECO's customers.

> Ratepayers should pay their fair share of costs associated with plant which they are receiving service. Unrecovered amounts associated with non-existent plan do not benefit ratepayers. […] recovery of the identified unrecovered costs associated with planned near-term retirements over a period that matches the remaining period the related assets will provide service ensures intergenerational equity.

[1] Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket Nos. 080677-EI and 090130-EI, *In re: Petition for increase in rates by Florida Power & Light Company, and 2009 depreciation and dismantlement study by Florida Power & Light Company*, pages 21-23.

**A.** a. The company has four coal-fired generating assets located at Big Bend Station and one IGCC generating unit at its Polk Power station. The existing retirement dates of the Big Bend coal units are 2035 for Unit 1, 2038 for Unit 2, 2041 for Unit 3, and 2049 for Unit 4. The company has been evaluating the remaining life cycle costs of its coal-fired units compared to other options, but has not completed its analysis. A firm decision on when, or if, early retirement of any of those units would take place has not been made.

b. The company anticipates beginning retirement of its AMR meters in December of 2018. Additionally, the company expects to complete the removal of AMR and replacement to AMI meters in two years.

c. The net book value of the AMR meters is expected to be approximately $39 million at the time of removal commencement. The annual depreciation expense expected over the settlement term is approximately $5 million per year.

d. Please see attached.

Please note that the asset balances for September 2017 are based on the actual plant records and can be uniquely identified by retirement units. The breakout by type for depreciation expense, reserve and net book value are based on an allocation since the depreciation and reserve amounts for group depreciated assets are not maintained below the depreciation group level.

The AMI Pilot Program for Meters began in 2016, therefore the 2017 reserve balance will include the ending reserve amount from December 2016 in addition to the 2017 depreciation expense.

The 2018 – 2021 plant amounts for AMI are based on estimates at this point in time and are subject to change.

e. Paragraph 8(b) is a Negotiated Term intended to specify that AMR and coal-fired generation assets, if retired, would remain in plant in service and rate base and would continue to be depreciated at their present depreciation rates as if there were no early retirements until the next depreciation study filed in advance of the next rate case.

Absent the Commission's approval of the 2017 Agreement, or in the absence of a settlement agreement, the company would seek an accelerated depreciation schedule when the assets were retired and removed from rate base. The accelerated depreciation would result in an increase to depreciation expense, which could contribute to a need for a base rate increase. Pursuant to the 2017 Agreement, the company agrees not to seek rate relief to be effective during the Term, which would include the incremental depreciation amounts in accelerated recovery schedules, which would benefit customers.

**Plant Balance**

| | Sep 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| 37000 | | | | | |
| Other | 13,138,130 | 13,138,130 | 13,138,130 | 13,138,130 | 13,138,130 |
| AMR | 69,655,204 | 69,655,204 | 69,655,204 | 69,655,204 | 69,655,204 |
| AMI | 1,361,336 | 10,480,687 | 91,546,687 | 176,333,687 | 181,133,687 |
| **Total** | **84,154,670** | **93,274,021** | **174,340,021** | **259,127,021** | **263,927,021** |
| | | | | | |
| %AMR Assets | 83% | 75% | 40% | 27% | 26% |
| %AMI Assets | 2% | 11% | 53% | 68% | 69% |

**Annual Depr Expense**

| | Sep 2017 | 2018 | 2019 | 2020 | 2021 | Depr Rate |
|---|---|---|---|---|---|---|
| 37000 | | | | | | |
| Other | 709,810 | 945,945 | 945,945 | 945,945 | 945,945 | **7.20%** |
| AMR | 3,763,244 | 5,015,175 | 5,015,175 | 5,015,175 | 5,015,175 | **7.20%** |
| AMI | 50,413 | 754,609 | 6,591,361 | 12,696,025 | 13,041,625 | |
| **Total** | **4,523,467** | **6,715,729** | **12,552,481** | **18,657,145** | **19,002,745** | |

**Reserve Balance**

| | Sep 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| 37000 | | | | | |
| Other | 5,698,630 | 6,644,576 | 7,590,521 | 8,536,466 | 9,482,412 |
| AMR | 26,180,991 | 31,196,165 | 36,211,340 | 41,226,515 | 46,241,689 |
| AMI | 58,693 | 813,303 | 7,404,664 | 20,100,690 | 33,142,315 |
| **Total** | **31,938,314** | **38,654,044** | **51,206,525** | **69,863,671** | **88,866,416** |

**Net Book Value**

| | Sep 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| 37000 | | | | | |
| Other | 7,439,499 | 6,493,554 | 5,547,609 | 4,601,663 | 3,655,718 |
| AMR | 43,474,214 | 38,459,039 | 33,443,864 | 28,428,689 | 23,413,515 |
| AMI | 1,302,643 | 9,667,384 | 84,142,023 | 156,232,997 | 147,991,372 |
| **Total** | **52,216,356** | **54,619,977** | **123,133,496** | **189,263,350** | **175,060,605** |

**23.** Please refer to Paragraph 8(c) of the 2017 Amended and Restated Stipulation and Settlement Agreement. In consideration of Rule 25-6.0436(4)(d), F.A.C., what is meant by the phrase "[t]he depreciation and dismantlement study period shall match the test year in the company's MFRs…?"

**A.** Paragraph 8(c) is a Negotiated Term intended to ensure that the company submits a depreciation and dismantlement study that reflects rates corresponding with the timing of its test year MFRs. Under this approach, the depreciation expense reflected in the test year would be consistent with a full year's amount of depreciation based on the rates in the depreciation and dismantlement study.

**24.** Refer to Paragraph 11(a), which states that Tampa Electric will not enter into new financial natural gas hedging contracts through December 31, 2022.

a. Please identify the volume of natural gas for delivery in 2018 that will be purchased under previously-executed hedging contracts.

b. Please identify the volume of natural gas for delivery in 2019 that will be purchased under previously-executed hedging contracts.

c. Please identify the volume of natural gas for delivery in 2020 that will be purchased under previously-executed hedging contracts.

d. Please identify the month and year when all previously-executed hedging contracts will be fulfilled.

e. Please explain why the end-date of the 2017 Settlement (12/31/21) is different than the end-date of Paragraph 11(a), which is 12/31/22.

**A.** a. 5,880,000 MMbtus have been hedged for 2018.

b. No hedges have been put in place for 2019.

c. No hedges have been put in place for 2020.

d. November 2018

e. Paragraph 11(a) is a Negotiated Term. The parties agreed in the negotiation process to extend the moratorium on hedging one year longer than the Term of the 2017 Agreement.

**25.** Refer to Paragraph 11(c), addressing sales from solar assets.

a. Please define the term “separated sales,” providing examples.

b. Please define the term “stratified sales,” providing examples.

c. Describe how the sales addressed in Paragraph 11(c) are currently recorded in the Company’s books and records. As appropriate, identify the specific monthly schedules that are used for this purpose.

d. Assuming the Company’s Petition is approved, describe the changes, if any, in how the sales addressed in Paragraph 11(c) would be recorded in the Company’s books and records during the Term.

e. Hypothetically, if the Company made a “separated/stratified sale” for 100,000 kWh of energy, will the Company’s books and records indicate the generating asset(s) and/or fuel type used to produce the kWh for that sale? Please explain your response.

f. Upon the expiration of the Term, is it the Company’s intent to begin making “separated/stratified sales from energy generated by solar assets being recovered through a SoBRA?” Please explain your response.

**A.** a. Separated sales are firm wholesale sales greater than one year in duration that commit production capacity of the selling utility to a wholesale purchaser. The production plant assets and operating expenses associated with the sale are separated or removed from the retail jurisdictional cost responsibility. An example would be a firm power sale agreement for 50 MW with a two-year duration.

b. Stratified sales are sales made under the company’s Cost-Based Power Sales Tariff. Charges are based on costs for the units expected to serve the sale’s load. An example would be a 50 MW sale of peaking power. Terms of the sale would be specific to serving the sale from peaking units.

c. The costs associated with serving a separated sale are identified and separated from the retail (FPSC) jurisdiction and assigned to the wholesale (FERC) jurisdiction. Because Tampa Electric serves in only one state, all costs are assigned to either the FPSC or FERC jurisdictions. Retail cost responsibility is adjusted by 1) a reduction in the cost of service retail revenue requirements at the time of the utility’s next base rate case; 2) continued monthly surveillance reporting, which, in the event a utility is over-earning, generates additional funds subject to Commission jurisdiction; or 3) through credits in the retail fuel and purchased power cost recovery clause equal to the selling utility’s system average fuel costs.

d. Under Paragraph 11(c), separated/stratified sales are not allowed to be made from the energy generated by any solar assets being recovered through a SoBRA during the Term. This does not cause changes in how other sales are recorded in the company’s books and records. In addition, the company does not currently have any separated sales.

e. Yes. In the hypothetical scenario described, the costs of a separated sale would be directly assigned to the wholesale jurisdiction for cost recovery purposes. The company would maintain records of the generating assets and/or fuel type expected to serve the sale, and the costs and revenues associated with the wholesale jurisdictional transaction would be excluded from the retail jurisdication in its books and records.

f. No. The company has no current intent to make separated or stratified sales upon the expiration of the term, unless circumstances change where these would be in the best interest of the general body of customers.

**26.** Refer to Paragraph 11(d), which addresses crediting the fuel clause when certain sales are made.

a. Please define the term "non-separated wholesale energy sales," providing examples.

b. Describe how the sales addressed in Paragraph 11(d) are currently recorded in the Company's books and records. As appropriate, identify the specific monthly schedules that are used for this purpose.

c. Assuming the Company's Petition is approved, describe the changes, if any, in how the sales addressed in Paragraph 11(d) would be recorded in the Company's books and records during the Term.

**A.** a. Non-separated wholesale energy sales are wholesale sales less than one year in duration. They are not separated because they are considered to be sporadic or non-recurring energy sales that do not require a long-term capacity commitment by the selling utility. The term of the sale may be hourly, blocks of hours, daily, weekly, monthly, or seasonal. These sales are typically recallable by the selling utility if it needs to serve its native load, and non-separated sales are not assigned cost responsibility through the jurisdictional cost of service study or monthly FPSC surveillance separation process. Since retail customers are responsible for the costs to make the sale, the margins of the sales are returned to customers through the fuel clause, subject to any applicable sharing specified by Order No. PSC-2000-1744-PAA-EI, and any transmission revenues or separately identifiable capacity revenues associated with the sales are credited to the capacity clause.

b. See the company's response to subpart 26a, above. The company reports non-separated, non-emergency sales to the FPSC each month on its Fuel Schedule A6. The company reports transmission and capacity revenues of sales on the monthly Fuel Schedule A12.

c. The sales would be recorded in the company's books and records during the Term of the agreement in the same manner they currently are. The only difference would be the different thresholds applicable to sharing under the proposed optimization mechanism, if approved as part of the Settlement agreement, instead of the current non-separated sales incentive approved by Order No. PSC-2000-1744-PAA-EI. The company would continue to follow the current practice of crediting the fuel clause with an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours it was sold, as required by Order No. PSC-2001-2371-FOF-EI.

**27.** Please refer to Paragraphs 10 and 11(e). Please explain if solar renewable energy credits are sold would the profits from this sale be accounted for in the $4.5MM/year to $8.0MM/year range determined by the Asset Optimization/Incentive Mechanism program.

**A.** No. Any sales of solar renewable energy credits would not be considered as part of the Asset Optimization/Incentive Mechanism.

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is Managing Director, Regulatory Affairs Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 11–12, 17-19, and 22-27) to the best of his information and belief.

Dated at Tampa, Florida this 16 day of October, 2017.

Carlos Aldazabal
____________________________________

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown
____________________________________

My Commission expires

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

# A F F I D A V I T

STATE OF FLORIDA )
)
COUNTY OF HILLSBOROUGH )

Before me the undersigned authority personally appeared William R. Ashburn who deposed and said that he is Director, Pricing and Financial Analysis, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 1-4, 16 and 20-21) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

William Ashburn

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

My Commission expires ________________

# A F F I D A V I T

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared R. James Rocha who deposed and said that he is Director, Generation Asset Strategy, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 10 and 13-14) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

R James Rocha
___________________________________

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown
___________________________________

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

My Commission expires ___________________________

# AFFIDAVIT

STATE OF FLORIDA )
)
COUNTY OF HILLSBOROUGH )

Before me the undersigned authority personally appeared Mark D. Ward who deposed and said that he is Director, Renewable Energy, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 5-9, and 15) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

Mark D. Ward

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown

My Commission expires Notary Public State of Florida Paula K Brown My Commission GG 032689 Expires 12/04/2020