FLORIDA PUBLIC SERVICE COMMISSION

EXHIBIT INDEX

FOR THE HEARING DATED 07/22/2025 IN DOCKET 20250078

FPSC EXH NO. 1

ADMITTED

B1

Docket No. 20250078-EI
Comprehensive Exhibit List for Entry into Hearing Record
July 22 – July 23, 2025

Exhibit #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
1.		Exhibit List	Comprehensive Exhibit list		
DUKE ENERGY FLORIDA, LLC(DEF) - DIRECT					
2.	Dave Rahman	DR-1	DEF Electric Facilities Map (DEF general map)	1 - 4	
3.	Dave Rahman	DR-2	Deland West to Dona Vista Reliability Upgrade Project Map	1 - 4	
4.	Dave Rahman	DR-3	Schedules 3.1.1 and 3.2.1 of DEF's Ten Year Site Plan, filed April 1, 2025	1 - 4	
5.	Dave Rahman	DR-4	Load Flow Summary Table **CONFIDENTIAL**	1 - 4	
6.	Dave Rahman	DR-5	DEF Transmission Planning Criteria	1 - 4	
7.	Dave Rahman	DR-6	Alternative Projects Load Flow Summary Table **CONFIDENTIAL**	1 - 4	
8.	Dave Rahman	DR-7	DeLand West to Dona Vista 230 kV Line Project Indicative Schedule of Licensing, Design, and Construction	1 - 4	
9.	Dave Rahman	DR-8	Project Decision Matrix	1 - 4	
10.	Dave Rahman		Appendix to the Petition to Determine Need for DeLand West – Dona Vista Transmission Line in Volusia and Lake Counties **CONFIDENTIAL**	1 - 4	
11.			Notices of Final Hearing and Affidavits of Publication	1 - 4	

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FPSC EXH NO. 1

ADMITTED

B2

Docket No. 20250078-EI
Comprehensive Exhibit List for Entry into Hearing Record
July 22 – July 23, 2025

Exhibit #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF HEARING EXHIBITS					
12.	Rahman (1-5)	Staff Exhibit 12	DEF's response to Staff's First Set of Interrogatories Nos. 1-5 **ATTACHMENTS (1, 3)** 1: BN 20250078-STAFFROG1-00000001 3: BN 20250078-STAFFROG1-00000002-00000003 (Confidential) **CONFIDENTIAL (3, 4)** DN 05255-2025	1, 2, 3, 4	
13.	Rahman (6, 8-10); Oliver (7)	Staff Exhibit 13	DEF's response to Staff's Second Set of Interrogatories Nos. 6-10 **ATTACHMENTS (7)** 7: BN 20250078-STAFFROG1-00000004-00000014	1, 2, 3, 4	
14.	Rahman (11-13)	Staff Exhibit 14	DEF's response to Staff's Third Set of Interrogatories Nos. 11-13	1, 2, 3, 4	
STIPULATIONS					
15.		Staff Exhibit 15	Duke Energy Florida, LLC's Proposed Stipulations	1-5	

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FPSC EXH NO. 1

ADMITTED

HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**

Exhibit DR-1

DEF Electric Facilities Map (DEF general map)

ATTACHMENT I

DUKE ENERGY FLORIDA

ELECTRIC FACILITIES MAP

(GENERAL MAP)

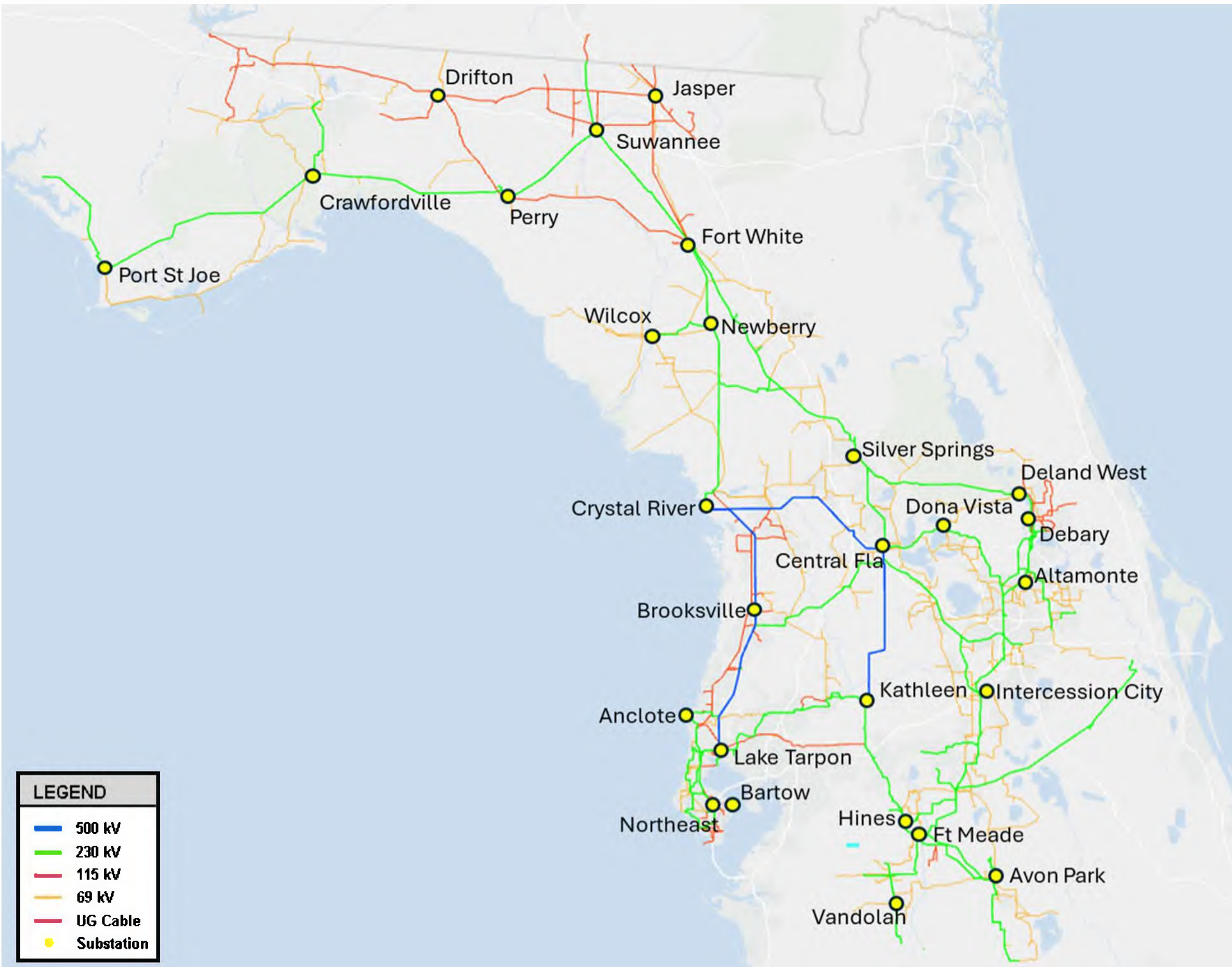

Exhibit DR-2

Deland West to Dona Vista Reliability Upgrade Project Map

FPSC EXH NO. 3

ADMITTED

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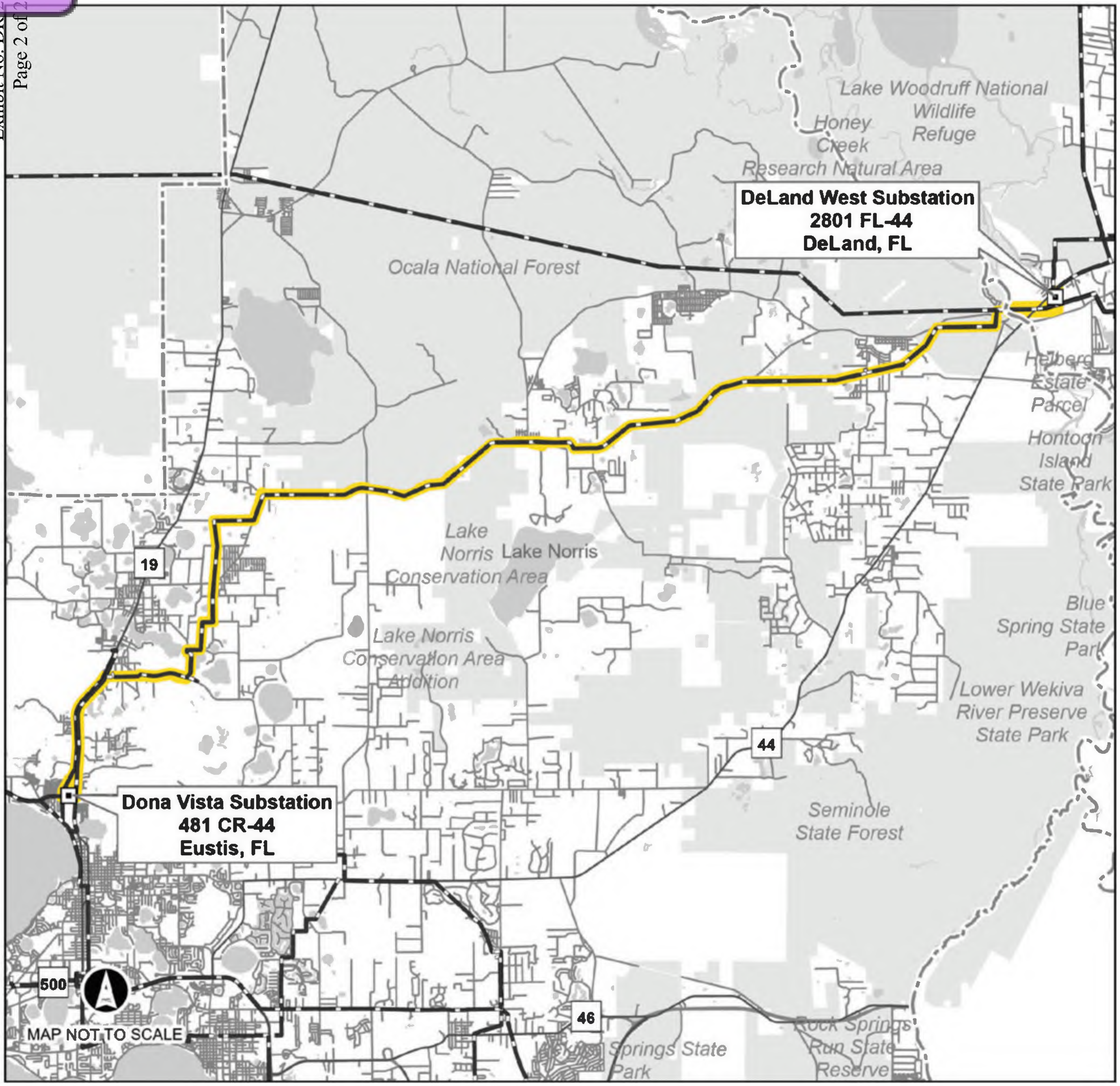
DELAND WEST TO DONA VISTA RELIABILITY UPGRADE PROJECT



Legend

- Existing Substation Location
- Existing Duke Energy Transmission Line
- Transmission Line Corridor
- Lakes and Ponds
- Conservation Land
- County Boundary

BUILDING A SMARTER ENERGY FUTURE®

FPSC EXH NO. 4

ADMITTED

Docket No: 20250078-EI
Duke Energy Florida
Witness: Dave Rahman
Exhibit No. DR-3

Exhibit DR-3
Schedules 3.1.1 and 3.2.1 of DEF's Ten Year Site Plan, filed April 1, 2025

C1-27

FPSC EXH NO. 4

ADMITTED

DUKE ENERGY FLORIDA

SCHEDULE 3.1.1

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
2024	10,539	652	9,887	415	357	548	91	443	80	8,605
FORECAST:										
2025	10,810	351	10,459	415	380	581	94	468	80	8,792
2026	10,957	451	10,506	415	386	600	97	471	80	8,908
2027	11,052	451	10,601	415	392	618	101	475	80	8,971
2028	11,070	451	10,619	415	393	637	104	479	80	8,962
2029	11,145	451	10,694	415	394	656	107	484	80	9,009
2030	11,307	451	10,856	415	395	675	110	488	80	9,143
2031	11,392	451	10,941	415	396	694	113	492	80	9,202
2032	11,522	401	11,121	415	397	713	116	495	80	9,305
2033	11,633	401	11,232	415	398	732	119	498	80	9,390
2034	11,771	401	11,371	415	399	751	123	500	80	9,504

Historical Values (2015 - 2024):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2025 - 2034):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Docket No: 20250078-EI
Duke Energy Florida
Witness: Dave Rahman
Exhibit No. DR-3

DUKE ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014/15	10,648	1035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
2023/24	8,854	506	8,348	412	634	1,055	87	263	172	6,232
FORECAST:										
2024/25	11,795	952	10,843	412	642	1,080	90	269	197	9,105
2025/26	12,000	1,052	10,947	412	650	1,108	94	269	198	9,269
2026/27	12,099	1,052	11,047	412	658	1,136	97	270	199	9,328
2027/28	11,603	451	11,151	412	659	1,165	100	270	200	8,796
2028/29	11,695	451	11,244	412	660	1,196	103	270	201	8,853
2029/30	11,787	451	11,336	412	661	1,226	106	271	202	8,910
2030/31	11,787	401	11,387	412	662	1,255	109	271	202	8,876
2031/32	11,853	401	11,452	412	663	1,285	112	272	202	8,907
2032/33	11,934	401	11,533	412	664	1,314	116	272	203	8,954
2033/34	12,066	401	11,665	412	665	1,343	119	272	204	9,050

Historical Values (2015 - 2024):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Projected Values (2025 - 2034):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FPSC EXH NO. 5

ADMITTED

C1-30

Exhibit DR-4

Load Flow Summary Table

FPSC EXH NO. 5

ADMITTED

C1-31

REDACTED

[redacted]

C1-31

Exhibit DR-5

DEF Transmission Planning Criteria

DEF plans, designs, and operates its transmission system to comply with the North American Electric Reliability Corporation (NERC) Reliability Standards. The NERC Reliability Standard TPL-001-5.1 defines scenarios and expected levels of system performance that the Bulk Electric System (BES) should comply with in the long-term planning horizon. In general, the system will remain stable and both thermal and voltage limits will be within applicable facility ratings for each of the contingency categories listed on Table 1 of NERC Reliability Standard TPL-001-5.1 (Attachment 1 to this exhibit). DEF follows the standard guidance on system performance requirements for its transmission planning criteria. Category P0 addresses system performance with no contingencies and all facilities in service. Categories P1 and P2 address system performance following a single contingency. Categories P3 through P7 address system performance following multiple contingencies. Finally, the standard addresses system performance following Extreme Events where multiple facilities are removed from service. The need for transmission system upgrades is most frequently based on potential overload and/or under-voltage conditions associated with Category P2 through P7 type contingencies. For each of these types of contingencies, the response of the power system is analyzed to ensure system performance, resulting conditions, and severity of potential overload/undervoltage conditions are consistent with the NERC Reliability Standards. Generally, for Extreme Events, contingency analysis is used to identify potential situations of cascading interruptions and/or instability. There may be isolated cases where reliability concerns combined with other factors may justify a more conservative approach in developing alternatives than the normal planning criteria.

In addition to the NERC reliability standards, DEF also plans to the FRCC Regional Transmission Planning Process ("RTPP", document FRCC-MS-PL-018, Attachment 2 to this exhibit). The analyses performed as part of the RTPP are conducted under the same assumptions and requirements as that of TPL-001-5.1, the primary difference between the two being that the FRCC treats the 69 kV system as if it is part of the BES (normally 100 kV and higher voltage facilities).

In addition to the NERC and FRCC reliability standards, DEF develops projects to address other changes to the BES. These include changes of power transfers across areas associated with transmission service, generator interconnection requests, or generation retirements; improvement of overall reliability of the BES and non-BES (i.e., 69 kV transmission); and providing delivery point service as needed to wholesale or other large customers.

DEF also states its transmission planning criteria as part of its annual Federal Energy Regulatory Commission ("FERC") Form No. 715 Filing. Each transmitting utility that operates integrated transmission system facilities that are rated at or above 100 kV must annually submit this filing to the FERC. This filing includes regional power flow data, transmission system maps and diagrams used by DEF for transmission planning, a detailed description of DEF's transmission planning reliability criteria, a detailed description of DEF's transmission planning assessment practices (including, but not limited to, how reliability criteria are applied and the steps taken in performing transmission planning studies), and a detailed evaluation of DEF's anticipated system performance as measured against its stated reliability criteria using its stated assessment practices.

Attachment 1 to Exhibit DR-5

NERC Reliability Standard TPL-001-5.1, Table 1

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment 2 to Exhibit DR-5

FRCC Regional Transmission Planning Process

FRCC-MS-PL-018

FRCC
Florida Reliability Coordinating Council, Inc.

FRCC Document Classification: Public – This document may be shared freely with no access or use restrictions.

FRCC Regional Transmission Planning Process
FRCC-MS-PL-018
Effective Date: 9/1/2024
Version: 7

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TITLE	NAME	DATE
Version Author	Adrian Raducea	03/22/2024
Document Review	Regional Projects Subcommittee	04/26/2024
Document Owner/Approval	FRCC Planning Committee FRCC Board of Directors	05/07/2024 08/28/2024

Document Subject Matter Expert: FRCC Director of Planning
Original Author: Order 1000 Steering Task Force
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File Name: frccmspl018_rgnltransplan
Document ID #: FRCC-MS-PL-018

This FRCC Regional Transmission Planning Process is based on the FERC approved Order 1000-compliant Open Access Transmission Tariffs ("OATT") of the Florida transmission providers, and includes Interregional Transmission Coordination Procedures also approved by FERC (see the July 30, 2015 and August 20, 2015 FERC Orders). Upon issuance of future FERC order(s) acting on or impacting the Florida transmission providers' OATT sections on their Transmission Planning Processes, the FRCC Planning Committee shall cause this Regional Transmission Planning Process to be amended and approved by the FRCC Board of Directors to incorporate the Florida transmission providers' FERC-approved OATTs.

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Page

1.0 Purpose

The objective of the FRCC Regional Transmission Planning Process ("Planning Process," "Regional Plan" or "RTPP") is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a reliable, cost effective and efficient transmission network in the FRCC Region.

The RTPP is intended to develop a reliable, cost effective and efficient regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent transmission planning environment.

The RTPP is intended to ensure the long-term reliability of the Bulk Electric System ("BES") in the FRCC region. However, nothing in this process is intended to limit or override rights or obligations of transmission providers, owners and/or transmission customers/users contained in any rate schedules, tariffs or binding regulatory orders issued by applicable federal, state or local agencies. In the event that a conflict arises between the RTPP and the rights and obligations included in those rate schedules, tariffs or regulatory orders, and the conflict cannot be mutually resolved among the appropriate transmission providers, owners, or customers/users, any affected party may seek a resolution from the appropriate regulatory agencies or judicial bodies having jurisdiction.

2.0 Terms and Definitions

2.1 Refer to North American Electric Reliability Corporation ("NERC") Glossary of Terms for definitions of capitalized terms not listed below.

2.2 Approved Cost Effective or Efficient Regional Transmission Solutions ("CEERTS") Project

A project that has achieved successful completion of the items in the Biennial Transmission Planning Process ("BTPP") steps 1 through 6, and approved by the FRCC Board of Directors for inclusion in the regional transmission plan. Any transmission projects that are being avoided due to the approved CEERTS project are removed from the regional transmission plan and associated regional models.

2.3 Enrolled Transmission Provider

Transmission provider that has been granted enrollment in the planning process for purposes of regional cost allocation by the FRCC.

2.4 Project Sponsor

The entity (or entities) that submit all of the required elements of a project proposal that is to be considered a potential CEERTS project.

2.5 Regional Plan

The "Regional Plan" also referred to as the "Regional FRCC Transmission Plan", is developed on an annual basis and consists of the Long-Range Study (including operational procedures) approved by the Board and the list of projects included in the Project Information Form ("PIF") as developed under the Annual Transmission Planning Process (ATPP).

3.0 Background

The RTPP is implemented in the FRCC as two distinct and separate processes: (1) the Annual Transmission Planning Process ("ATPP") and (2) the Biennial Transmission Planning Process ("BTPP").

The ATPP is the result of coordinating each of the FRCC members' local plans to develop the overall Regional Plan. The ATPP is closely tied to the region's NERC compliance activities, many of which have annual requirements for compliance with Reliability Standards for modeling (MOD), protection and control (PRC), facilities (FAC), and transmission planning (TPL).

The BTPP is initiated in odd-numbered years and runs concurrently with the ATPP in order to identify and evaluate more cost effective or efficient regional transmission solutions, or "CEERTS" projects. The BTPP includes a regional evaluation of the Board-approved plan to determine if there are solutions meeting CEERTS project criteria that could be proposed for regional cost allocation. The evaluation also considers potential transmission solutions to transmission needs driven by public policy requirements[1].

4.0 Applicability

4.1 FRCC Planning Coordinator/Authority

The ATPP portion of this RTPP is applicable to the FRCC as a Planning Coordinator/Authority. Note: The use of the terms "Planning Coordinator" and "Planning Authority" are interchangeable as it relates to this document.

4.2 Enrolled Transmission Providers

The cost allocation portion of the BTPP included in this RTPP is applicable to Enrolled Transmission Providers.

5.0 Responsibilities

5.1 FRCC Board of Directors ("FRCC Board" or "Board")

The FRCC Board shall have the responsibility to approve this document and ensure this process is fully implemented.

5.2 FRCC Planning Committee ("FRCC PC")

[1] To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency).

The FRCC PC is responsible for approving and endorsing the document for FRCC Board approval. The FRCC PC shall direct the Transmission Technical Subcommittee (“TTS”), the Stability Analysis Subcommittee (“SAS”), the Resource Subcommittee (“RS”), and the Regional Projects Subcommittee (“RPS”) as appropriate, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the RTPP.

5.3 FRCC Regional Projects Subcommittee (“RPS”)

As directed by the FRCC PC, the RPS shall be responsible for supporting the efforts associated with the BTPP or other duties as assigned by the FRCC PC. The RPS is also responsible for this document’s review and modification before submitting the document for FRCC PC approval.

5.4 FRCC Transmission Technical Subcommittee (“TTS”)

As directed by the FRCC PC, the TTS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

5.5 FRCC Stability Analysis Subcommittee (“SAS”)

As directed by the FRCC PC, the SAS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

5.6 FRCC Resource Subcommittee (“RS”)

As directed by the FRCC PC, the RS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

6.0 Principles

It is the intent of the FRCC that the Planning Process be conducted in a coordinated, open, and transparent manner, including facilitation of information exchange, in such a way that it ensures fair treatment for all customers/users, owners and operators of the transmission system. This will be accomplished through the processes described herein.

6.1 Coordination

The FRCC expects its member transmission providers to consult and interact directly with their customers and stakeholders in providing transmission service and generator interconnection service, as well as with their neighboring transmission providers and FRCC Staff, on a regular basis. An open dialogue between transmission customers and their transmission providers takes place regarding customer needs. This interaction and dialogue between the customers and transmission providers are part of the transmission providers’ local transmission network planning processes. Within those processes, topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan.

The transmission providers communicate with their neighboring transmission providers on a regular basis, and the transmission providers facilitate communication and consultation between customers and their neighboring transmission owners/providers, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level with FRCC Staff, leading to each transmission provider providing an initial transmission plan which, when consolidated, becomes the initial FRCC regional transmission plan.

The initial transmission plans submitted to the FRCC by the transmission providers, which results from their local transmission network planning processes will be posted by the FRCC in accordance with Step 1 of the FRCC ATPP in Section 7.1 below. The initial transmission plan is reviewed by the FRCC Staff as well as all interested transmission customers and stakeholders.

The FRCC Committee process is used to finalize the initial transmission plan as submitted to the FRCC. In addition to transmission customers and stakeholders being provided timely and meaningful input and participation during the planning process with the transmission providers, the transmission customers and stakeholders are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any transmission providers' initial transmission plan submittal in accordance with Step 2 of the FRCC ATPP.

This FRCC review process normally commences shortly after the submittal of the Ten-Year Site Plans ("TYSP") to the Florida Public Service Commission ("FPSC") on April 1st of each year. Once issues raised by interested stakeholders are addressed, including consideration of proposed CEERTS projects as set forth in section 7.2 below, the FRCC PC approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in February of each year, the FRCC sends notice to the FPSC that the final regional transmission plan documents are available for their use and review upon request. Unresolved issues may be resolved under the FRCC Dispute Resolution Procedures.

6.1.1 Coordination of Transmission Service Requests

In order to coordinate transmission service requests within the FRCC, transmission providers will provide their long-term firm transmission service requests and generator interconnection service requests, in queue order, to the FRCC in a common format. The FRCC will consolidate all individual queues for coordination purposes and will post the consolidated queue for coordination purposes for all FRCC members to view.

6.1.2 Regional Reliability Evaluation Process

Through the *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests (FRCC-MS-PL-054)*, the FRCC Staff facilitates and coordinates the identification of potential third-party impacts within the FRCC region and evaluates transmission service requests to ensure that the transmission system within the FRCC region remains reliable, adequate and secure.

6.2 Openness

The openness principle is incorporated in this *FRCC Regional Transmission Planning Process* in which member transmission providers participate, along with other parties, in the committee and working processes at the FRCC as described below. The participants in the planning process at the FRCC are the sector representative of the FRCC PC. A list of representatives may be found on the FRCC website under the *FRCC PC Member List* (pursuant to 6.2.4).

The *Rules of Procedure for FRCC Standing Committees'* document on the FRCC website describes the FRCC PC structure and processes as they relate to Organization Structure, Standing Committee Representation, Standing Committee Quorum and Voting, Duties of Officers and Representatives, General Procedures for Standing Committees, FRCC Representation on NERC Committees, Procedures of Minutes of Meetings and Conduct of the Meeting.

If an interested entity is an FRCC member, they may participate in the committees via participation within one of the identified sectors (Supplier Sector, Non-Investor Owned Utility Wholesale Sector, Load Serving Entity Sector (including municipals and cooperatives), Generating Load Serving Entity Sector, Investor Owned Utility Sector, and General Sector (this sector provides for any entity or individual's participation)). If a party is not a member, they may participate in open committee meetings that are scheduled as part of the BTPP process. Moreover, at the FRCC regional level interested stakeholders have an opportunity to raise any special requirements that they have and believe have not been addressed at the local level.

Customer input is included in the early stages of the development of the transmission plans, as well as during and after plan evaluation processes. Detailed evaluation and analysis of the transmission owners'/providers' plans are conducted by the FRCC subcommittees under the direction of the FRCC PC. Such evaluation and analysis provides the basis for possible changes to the transmission owners'/providers' plans that could result in a more reliable and more robust transmission system for the FRCC Region. The FRCC PC meets on a regular basis, usually monthly, with two weeks prior notice.

6.2.1 Meetings

The FRCC meeting dates are provided in the *FRCC Calendar* document on the FRCC website and the chairs and member representatives for the various committees are posted on the FRCC website under the *FRCC Committees* (pursuant to 6.2.4). The meeting agenda for the FRCC PC is normally provided two weeks prior to the meeting to the committee members.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results will be exchanged, discussed or presented, are distributed by the FRCC.

6.2.2 Standards of Conduct

The FRCC has developed the *FERC Standards of Conduct Protocols for the FRCC* ("Standards of Conduct Protocols") document for the purpose of ensuring proper disclosure of transmission information in accordance with FERC requirements. The primary rule is that a transmission provider must treat all transmission customers, affiliated and non-affiliated on a non-discriminatory basis, and it cannot operate its transmission system to give a preference to any transmission customer or to share non-public transmission or customer information with any transmission customer.

The rules also prevent transmission function employees from sharing with their merchant employees and certain affiliates non-public transmission information about the transmission provider's transmission system or any other transmission system, which is information that the affiliated merchant employee receiving the information could use to commercial advantage. All documents created by, or for, the FRCC that contain non-public transmission information shall be handled consistent with the Standards of Conduct Protocols.

6.2.3 Rules of Procedure

The FRCC conducts the planning process in an open manner in such a way that it ensures fair treatment for all customers, stakeholders, owners and operators of the transmission system. Stakeholders have access to and participate in the FRCC planning process, as described in this document. The committees and subcommittees described in this document are stakeholder groups. The FRCC PC consists of six stakeholder sectors: Suppliers, Non-Investor Owned Utility Wholesalers, Load Serving Entities, Generating Load Serving Entities, Investor Owned Utilities, and General. The rules of procedure governing the FRCC PC in conducting this *FRCC RTPP* are posted under the *Rules of Procedure for FRCC Standing Committees* on the FRCC website.

The FPSC is encouraged to and does participate in the *FRCC RTPP*.

6.2.4 Confidential / Proprietary Information and CEII

This FRCC RTPP provides for the overall protection of all confidential and proprietary information that is used to support the planning process. A customer, stakeholder or other interested entity may enter into a confidentiality agreement with the FRCC and/or applicable transmission provider/owner, as appropriate, to be eligible to receive transmission information that is restricted due to Critical Energy Infrastructure Information ("CEII"), security, business rules and standards and/or other limitations. The FRCC procedure for requesting this type of information is delineated at the FRCC website under the *Request for FRCC Transmission Information* document.

6.3 Transparency

Providers, performing their local area planning processes, utilize the FRCC databanks as the base case for their studies. The FRCC databanks contain information provided by the FRCC member transmission providers and customers of projected loads, as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon. Within their local area planning processes, transmission providers make available to a transmission customer the underlying data, assumptions, criteria and underlying transmission plans utilized in their study processes.

Once the results of the transmission providers' local area planning processes are reflected in the FRCC's initial transmission plan, the FRCC seeks input and feedback from transmission customers and stakeholders for any issues or concerns that are identified and independently assesses the initial regional transmission plan from a FRCC regional perspective. A dialogue among the FRCC, transmission customers, stakeholders, and transmission owners/providers occurs within these planning processes to address any issues identified during the various steps.

When the FRCC regional transmission plan has been approved by the FRCC PC, it is sent to the FRCC Board for approval. After the FRCC Board approves the FRCC regional transmission plan, it is posted on the FRCC website and the FRCC sends notice to the FPSC that the final regional transmission plan is available for their use and review upon request.

Additionally, the FRCC compiles all of the individual transmission providers'/owners' FERC Form 715s within the FRCC region and files all FERC Form 715s on behalf of its members with the FERC on an annual basis.

6.3.1 Reliability Standards and Criteria

Studies conducted pursuant to this RTPP utilize the applicable reliability standards and criteria of the FRCC and NERC that apply to the Bulk Power System as defined by NERC. Such studies also utilize the specific design, operating and planning criteria used by FRCC transmission owners/providers. The transmission planning criteria are available to all customers and stakeholders. Transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process.

The FRCC subcommittees update and distribute transmission projects/upgrades project descriptions, scheduled in-service dates, and project status on a regular basis, no less than quarterly to the FRCC PC. The FRCC also updates and distributes on a periodic basis the load flow database. The FRCC prepares and posts system impact study schedules so that other potentially impacted transmission owners/providers can assess whether they are affected and elect to participate in the study analysis. The FRCC planning studies are also distributed by the FRCC and updated as needed. All entities that have transmission projects/upgrades in the regional transmission plan shall provide updates on such projects at least annually.

6.3.2 Additional Reports and Documents

The FRCC also produces the following annual reports which are submitted or made available to the FPSC. These reports and documents are also available to customers, stakeholders or other transmission owners/providers through the Information Exchange discussed in Section 6.4 below:

a. The Regional Load and Resource Plan contains aggregate data on demand and energy, capacity and reserves, and proposed new generating unit and transmission line additions for Peninsular Florida as well as statewide.
b. The Reliability Assessment is an aggregate study of generating unit availability, forced outage rates, load forecast methodologies, and gas pipeline availability.
c. The Long-Range Transmission Reliability Study is an assessment of the adequacy of Peninsular Florida's bulk power and transmission system. The study includes both short-term (1-5 years) detailed analysis and long-term (6-10 years) evaluation of developing trends that would require transmission additions or other corrective action. Updates on

regional areas of interest and/or constraints (e.g., Central Florida) are also addressed.

6.4 Information Exchange

Transmission providers participate in information exchange on a regular and ongoing basis with the FRCC, neighboring utilities, and customers. Transmission customers are required to submit data to the transmission providers in order to plan for the needs of network and point-to-point customers. Such data/information includes: load growth projections, planned generation resource additions/upgrades (including network resources), any demand response resources, new delivery points, new or continuation of long-term firm point-to-point transactions with specific receipt (i.e., source or electrical location of generation resources) and delivery points, (i.e., the electrical location of load or sink where the power will be delivered to), and planned transmission facilities.

The transmission providers utilize the information provided in modeling and assessing the performance of their systems in order to develop a transmission plan that meets the needs of all customers of the transmission system. The transmission providers exchange information with transmission customers to provide an opportunity for them to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by their transmission provider. Through this information exchange process, the transmission customers have an integral role in the development of the transmission plan. Consistent with the transmission providers' obligation under federal and state law, and under NERC and FRCC reliability standards, the transmission providers are ultimately responsible for their transmission plans.

6.4.1 FRCC Databank Development

The TTS sets the schedule for data submittal and frequency of information exchange which starts at the beginning of each calendar year. Updates and revisions are discussed at the FRCC PC meetings by the members. This process requires extensive coordination and information exchange over a period of several months as the FRCC develops electric power system load-flow databank models for the FRCC Region. The models include data for every utility in peninsular Florida and are developed and maintained by the FRCC.

The TTS is responsible for developing and maintaining power flow base cases. The FRCC power flow base case models contain the data used by the FRCC and transmission providers for intra- and inter-regional assessment studies, and other system studies. The models created also are the basis for the FRCC submittal to the NERC Multiregional Modeling Working Group ("MMWG"). TTS members support the data collection requirements and guidelines related to the accurate modeling of generation, transmission and load in the power flow cases. The *FRCC Load Flow & Short Circuit Data Bank Procedural Manual* provides the guidelines and procedures adopted for the load flow and short circuit databank development and maintenance efforts. They are intended to provide consistency in data submittals, improve coordination among developers and users of the databank, and increase understanding of the modeling assumptions used.

The FRCC maintains databanks of all FRCC members' projected loads and planned and committed transmission and generation projects, including upgrades, new facilities, and changes to planned in-service dates. These databanks are updated on a periodic basis. The FRCC maintains and updates the load flow, short circuit, and stability models. All of this above information is distributed by the FRCC, along with the FRCC transmission planning studies, subject to possible redaction of user sensitive or critical infrastructure information consistent with market and business rules and standards.

6.4.2 Transmission Developer Interconnection Requests

Any transmission developer that is not participating in the regional transmission planning process (and therefore not seeking regulated cost-of-service recovery) that proposes to develop a transmission project in the FRCC region shall provide to the FRCC PC and affected transmission providers in the FRCC region such information and data related to its proposed project that are necessary to allow the FRCC PC and affected transmission providers in the FRCC region to assess the potential reliability and operational impacts of the non-participant developer's proposed transmission facility on the transmission system in the region. That information should include: transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

The required information and data shall be provided with the transmission developer's interconnection request(s). Non-participant developers' transmission projects will not be included in long-term planning models or interconnected to the existing transmission system until and unless: 1) interconnection service has been requested of affected transmission provider(s); and 2) all interconnection studies have been completed.

7.0 Regional Transmission Planning Process Overview

Study Process

Studies conducted pursuant to this RTPP shall utilize the applicable criteria for NERC Reliability Standards and FRCC standards to the BES. Such studies shall also utilize the specific design, operating and planning criteria used by the transmission owners/providers to the extent these specific design, operating and planning criteria meet NERC and FRCC standards and criteria for reliability or are more stringent than any applicable NERC and FRCC standards and criteria for reliability.

For purposes of this RTPP, analysis of 69 kV transmission facilities within the region that do not fall under the NERC definition of BES may be included in studies, as though they were included in the NERC BES definition, in order to better coordinate and improve the transmission system in the FRCC Region.

The RTPP begins with the consolidation of the long-term transmission plans of all of the transmission owners/providers in the FRCC Region including any previously approved CEERTS projects. It is the FRCC's expectation that the long-term transmission plans incorporate the integration of new firm resources as well as other firm commitments. This will include modeling of all transmission facilities 69 kV and above or representative equivalents (facilities exempted by NERC or excluded from the BES by NERC definition may be represented by equivalent models).

Detailed evaluation and analysis of these plans will be conducted by the RPS/TTS/SAS/RS as applicable, or any consultants retained by the FRCC, in collaboration with the FRCC Staff, and directed by the FRCC PC. Such evaluation and analysis will provide the basis for potential changes to individual and/or regional transmission system plans that, if implemented, would result in a more reliable, cost effective or efficient transmission system for the FRCC Region.

The assessment of the long-term transmission plan shall be comprehensive and in-depth. While the final recommended plan may not call for the construction of all transmission facilities identified in various sensitivities, the assessment will provide valuable information on the strength of the transmission system to aid in understanding how the system would perform in various situations.

The examination of multiple expected system conditions shall be performed, including an assessment of areas with recurring, significant congestion. As determined by the FRCC PC, these conditions or sensitivities (beyond those sensitivities required by NERC standards) may include any of, but not be limited to, the types listed below:

- Transmission and/or generation facilities unavailable due to scheduled and/or forced outages.
- Weather extremes for summer and winter periods.
- Different load levels (e.g., 100%, 80%, 60%, and 40%) and/or periods of the year (winter, spring, summer and fall).
- Various generation dispatches that will test or stress the transmission system which may include economic dispatch from all generation (firm and non-firm) in the region.
- Reactive supply and demand assessment (e.g., generator reactive limits, power factor, etc.)
- A specific area where a combination/cluster of generation and load serving capability is among various transmission owners/providers in the FRCC that continually experience or is expected in the future to experience significant transmission congestion on their transmission facilities will be reviewed annually and restudied as required. The analysis should reflect the upgrades necessary to integrate new generation resources and/or loads on an aggregate or regional (cluster) basis.

  Additionally, such analysis may include an estimate of the cost of congestion, as appropriate.
- Other scenarios or system conditions as identified by the FRCC PC (e.g., stability analysis)

For the first 5 years of the planning period, a detailed evaluation will be conducted. For years 6 through 10, a more generalized higher-level study will be conducted.

The FRCC PC shall submit a formal report of the assessment and findings, including any recommendations to the Board. The FRCC PC shall also submit formal reports for the assessment and recommendation of CEERTS projects to the Board, as applicable. Such reports shall include action plans that identify:

- Any recommended modifications to transmission owners'/providers' long-term plans that, in the judgment of the FRCC PC, offer worthwhile enhancements to regional transmission grid reliability, including any CEERTS projects.

- The identification of those elements of the recommended plan that cannot be implemented due to the inability to obtain the required commitments of the affected transmission owner(s)/provider(s) and user(s) to implement the plan.
- The identification of an alternative plan that does have the commitment of the affected transmission owner(s)/provider(s) and user(s) with regard to implementation.
- Any minority views expressed by any member of the FRCC PC or Project Sponsor as well as the identification of any unresolved issues.

7.1 Annual Transmission Planning Process

A Regional FRCC Transmission Plan ("Regional Plan") shall be developed on an annual basis using the ATPP. The Regional Plan[2] takes into consideration the TYSPs that are required to be submitted to the FPSC on April 1st of each year.

Any generating or transmission entity not required to submit a TYSP to the FPSC, shall submit its ten-year plan, consistent with the requirements of the FPSC TYSP, to the FRCC on April 1st of each year. Such entity's ten-year plan shall include the generation expansion plans for load serving entities, firm/network use of transmission, and any planned/proposed transmission system changes, including additions, cancellations, deferrals, and retirements, by transmission owners/providers.

The Regional Plan also includes CEERTS projects identified and analyzed through the BTPP that have been approved by the Board. The BTPP runs concurrently with the ATPP.

Step 1

FRCC PC Initiates FRCC Transmission Planning Review and Coordination Process

Transmission owners/providers shall submit to the FRCC PC their latest 10-year expansion plan for their transmission system by every April 30th, including (1) a list of planned transmission projects and their associated in-service dates that provides for all of their firm obligations based on the best available information, and (2) a list of projects that were deferred, or cancelled from the previous 10-year expansion plan's original in-service date, and (3) any transmission facility retirements for inclusion into the load flow databank.

FRCC will post the initial regional transmission plan on the FRCC website consisting of these planned transmission projects along with their previous in-service dates, current in-service dates, and planned facility retirements.

Step 2

Feedback from Transmission Customers/Users/Others of Individual 10-Year Expansion Plan

Transmission customers/users and other affected parties shall submit to the FRCC PC and affected transmission owners/providers any issues or special needs they feel have not been adequately addressed by the applicable transmission owner's/provider's 10-year expansion plan, and the underlying evaluation demonstrating the rationale for their concern.

Step 3

Review and Assessment by the FRCC PC

The FRCC PC shall review and assess the initial regional transmission plan consisting of transmission owners'/providers' plans from an overall FRCC perspective, ensuring that all affected transmission

[2] The "Regional Plan" consists of the Long-Range Study (including operational procedures) approved by the Board and the list of projects included in the Project Information Form ("PIF").

customers'/users' issues have been identified.

The FRCC PC, the transmission owners/providers and the transmission customers/users shall consult, as appropriate, during this period to address the issues of all parties to ensure their due consideration with regard to possible inclusion into the Regional Plan.

The FRCC PC shall address any issue or area of concern not previously or adequately addressed, with emphasis on constructing a robust regional transmission system.

As identified under Information Exchange above, the databank used in the development of the Regional Plan will be updated annually with periodic revisions by the TTS. Members will re-confirm in-service dates for under-construction, planned, proposed and conceptual projects on at least a quarterly basis.

Members will bring to the attention of the TTS any project changes as soon as possible to allow potentially affected parties as much lead time as possible for implementing alternative solutions. Any changes to the databank that could materially impact the Regional Plan, or affected other parties, will be reviewed by the TTS to determine whether the Regional Plan should be revised to reflect those changes.

The TTS shall send the coordinated study (the preliminary Regional Plan) to the FRCC PC for approval. If required prior to approval, the FRCC PC shall form working group(s), as necessary, to address specific matter(s) that require further technical assessment or evaluation.

Step 4

Issuance of Preliminary Regional Plan

The FRCC PC shall issue the preliminary Regional Plan to all FRCC members, and shall identify any proposed modification to the original transmission owner's/provider's plan. The purpose of this step is to receive comments and to identify any remaining unresolved issues.

Step 5

Approval of Regional Plan

The FRCC PC shall present to the transmission owners/providers, affected transmission customers/users, and other FRCC members a general overview and comments on the preliminary Regional Plan, including proposed modifications to each transmission owner's/provider's individual transmission plan.

The FRCC PC shall identify and discuss minority opinions and unresolved issues.

The FRCC PC shall approve the Regional Plan and present it to the Board for its consideration. The Plan may include specific matters that require further technical assessment or evaluation that have been assigned to a working group, and some unresolved issues may still be pending final resolution.

The Board shall take action on the Regional Plan. The resultant Board approved Regional Plan shall be posted on the FRCC public website and the FRCC will send a notice to the FPSC that the final regional transmission plan is available for their use and review upon request.

Step 6

Unresolved Issues

If any member of the FRCC PC eligible to vote has an unresolved issue(s) after the FRCC PC approves the Regional Plan, said member may direct the FRCC PC to present such unresolved issue(s) to the Board at the same time the Regional Plan is presented for approval.

If the Board fails to satisfy the concerns of the party raising the unresolved issue(s), the party may request the matter be set for dispute resolution in accordance with procedures contained within the FRCC Bylaws.

7.2 Biennial Transmission Planning Process

The BTPP is the process by which transmission providers, FRCC Staff, and other FRCC members identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the Regional Plan and applies to reliability, economic and public policy regional transmission projects. The regional analysis will be initiated in mid-January of odd-numbered years by the RPS, under the direction of the FRCC PC, and shall utilize the standards, criteria, data, models, methods and studies of the local transmission plans, supplemented as necessary. The regional analysis conducted in the BTPP shall determine if there is a solution meeting CEERTS project criteria that could be proposed for regional cost allocation.

The regional analysis shall also include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified. The provisions for stakeholder involvement and input in the regional transmission plan, and the ability to propose CEERTS Projects on their own initiative, as set forth in these steps, are fully applicable to potential transmission solutions due to transmission public policy needs driven by public policy requirements.

Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the BTPP. The entity proposing a CEERTS project is referred to as the Project Sponsor. The Project Sponsor for a CEERTS project need not be the Project Developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, the RPS, made up of transmission providers and other interested entities, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the BTPP cycle.

7.2.1 Proactive Planning for Potential CEERTS Projects

Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form (PIF), approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

Alternative Projects

If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or alternative transmission project(s) which would also fully and appropriately address the same regional transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in Step 5C below.

If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

The RPS develops potential CEERTS project alternatives and solicits project sponsorship from Enrolled Transmission Providers and other entities which may have an interest in sponsoring potential CEERTS projects.

A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

- General description of the transmission facilities being proposed;
- General path of the transmission lines, if applicable; and
- Transmission systems that would interconnect with the potential CEERTS project.

The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice shall be posted by May 1st of the first year of the BTPP cycle to provide time for meeting sponsorship requirements by June 1st.

Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit, unless the Project Sponsors otherwise mutually agree to a different sharing of the deposit.

Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a Project Sponsor or joint Project Sponsor of a potential

CEERTS project shall not be eligible to be a developer of that project, unless the Project Sponsor(s) discontinue development of that project.

The Project Sponsor or joint Project Sponsors shall submit the potential CEERTS project for consideration by June 1st of the first year of the BTPP.

7.2.2 Analysis of Sponsored CEERTS Projects

Once potential CEERTS projects with sponsors are proposed for the BTPP, the following steps are carried out under the direction of the FRCC PC:

Step 1

FRCC PC Reviews CEERTS Project Submittals

To be eligible for approval by the Board for inclusion in the Regional Plan, a proposed CEERTS project must meet threshold criteria and the project submittal must include certain elements. The FRCC PC will review CEERTS Project Sponsor submittals and ensure that they meet the threshold criteria, and the minimum submittal requirements within 30-45 days following the submittals.

The following threshold criteria must be met for CEERTS projects:

- Be a transmission line 230 kV or higher and 15 miles or longer; or
- Be a substation flexible AC transmission system ("FACTS") device (e.g., series compensation or static var compensator) designed to operate at 230 kV or more; and
- Be materially different from projects already in the Regional Plan.[3]

Local transmission facilities located solely within a transmission provider's footprint (e.g., Balancing Authority area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the transmission providers to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

Minimum Requirements for CEERTS Project Submittals:

Project Sponsor Only

Project Sponsors that do not also intend to be a Project Developer of CEERTS projects must submit the following minimum set of information:

- General description of the transmission facilities being proposed;
- General path of the transmission lines; and
- Transmission systems that would interconnect with the proposed CEERTS project.

Project Sponsor/Developer

Project Sponsors that intend to be the Project Developer of CEERTS projects shall so indicate

[3] The FRCC will consider a CEERTS project to be materially different from another CEERTS project if, for example, it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or slight change in route.

and shall submit the following information:

- Transmission project technical information
  - Description of the transmission facilities being proposes (e.g., voltage levels);
  - General path of the transmission lines; and
  - Interconnection points with the existing transmission system.
- A cost estimate and a recommended in-service date for the project. A Project Developer may also submit a demonstration of its cost containment capabilities, including any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.
- A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

A Project Sponsor may also submit any studies and analysis it performed to support its proposed CEERTS project, including the below:

- Reliability impact assessment
- Load flow analysis that demonstrates performance utilizing the FRCC load flow model
  - o The Project Sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).
- Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

A deposit of $100,000[4] shall be submitted by the Project Sponsor at the time the project is submitted (e.g., June 1st of the BTPP cycle) for each CEERTS project.

If a submittal is incomplete, the FRCC PC shall inform the CEERTS Project Sponsor in writing within 15 days after the next regularly scheduled FRCC PC meeting of the specific deficiency(ies), and the Project Sponsor shall be given an opportunity, within 30 days, to submit the information required for a complete submittal.

Step 2

FRCC PC Updates FRCC Board and Posts Information on FRCC Website

[4] This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the Project Sponsor(s), as applicable). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the Project Sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the Project Sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures.

At the next Board meeting following the review in Step 1, the FRCC PC shall provide an update to the Board related to all projects that have been submitted and deemed complete. The FRCC PC shall post this information on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information). At that time, the FRCC PC shall also post on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information) any determination that a proposed CEERTS project is not materially different from a project or projects already in the Regional Plan. Such posting will include an explanation of the basis for the determination that the proposed CEERTS project is not materially different.

Step 3

Regional Projects Subcommittee Performs Technical Analysis with Independent Consultant and Drafts Report for the FRCC PC to Inform Board

During the succeeding three to five months following the Board meeting in Step 2 of the BTPP, the FRCC PC will assign the RPS to work together with an independent consultant to conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the Project Sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed under the direction of the FRCC PC.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the Project Sponsor. This analysis will examine the following:

1. Transmission project technical information:
   a) Description of the transmission facilities being proposed (e.g., voltage levels);
   b) General path of the transmission lines; and
   c) Interconnection points with the existing transmission system.

2. Load flow analysis that demonstrates adequate NERC Reliability Standards performance utilizing the FRCC load flow model.

3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan; or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified if there are no transmission projects currently planned for the relevant transmission need(s) (refer to **Alternative Projects** in 7.2.1).
   a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC's analysis.

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.
    a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and

6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project.

C. The FRCC PC will provide the CEERTS Project Sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the Board with a recommendation as to whether the proposed CEERTS project should proceed to Step 4 of the BTPP. The CEERTS Project Sponsor and stakeholders shall be given 15 days to also provide written comments on the report to the Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

Step 4

FRCC Board Reviews CEERTS Report with Project Sponsor(s) and Makes a Determination

Over a period of two-to-three months from receipt of the FRCC PC report and any comments on the report provided by the CEERTS Project Sponsor and stakeholders pursuant to Step 3 of the BTPP, the Board will review the FRCC PC report and any comments received and determine if the CEERTS project should proceed to Step 5 of the BTPP.

The CEERTS Project Sponsor shall be invited to be present and participate in any Board meeting that addresses the FRCC PC report in order to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

If the Board determines that the CEERTS project should proceed to Step 5 of the BTPP, the project(s) may be included as a sensitivity in the ATPP. If a CEERTS Project Sponsor does not agree with the Board's determination, then the Dispute Resolution Procedures in the FRCC Bylaws are available for use by the CEERTS Project Sponsor.

Step 5

Cost / Benefit Analysis Performed and FRCC PC Provides a Report to the FRCC Board

Over a period of two-to-four months from the Board approval of the continuation of the CEERTS project evaluation in Step 4, the process described below will be performed by the FRCC PC under the direction of the Board.

A. A meeting will be organized by the FRCC PC to provide the CEERTS Project Sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a Project Sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the Project Developer of the CEERTS project (if no entity expresses interest as the Project Developer, then the CEERTS project will not move forward and the projects in the Regional Plan that would have been avoided by the CEERTS project will remain in the Regional Plan). If multiple qualified Project Developers express an interest in developing a CEERTS project for which the Project Sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section A, the project information identified in Step 1 above, and these Project Developer proposals will be evaluated in the remainder of the steps identified in Step 5. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in Step 3 of the BTPP above and as set forth below.

   1. A cost-benefit analysis must be performed in accordance with Step 5 of the BTPP, part C for reliability/economic projects by an independent consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

   2. For a project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under section 7.3 of the RTPP, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed, except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected.

   The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 7.2.2.4 under Step 5C below.

<u>Cost Benefit Analysis</u>

C. CEERTS Project Cost-Benefit Analysis

   An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for Project Sponsor and stakeholder review, as set forth in Step 5D. The independent consultant will determine if the benefit-to-cost ratio, which is the sum of the “Total Estimated Avoided Project Cost Benefit,” “Total

Estimated Alternative Projects Cost Benefit" and "Total Estimated Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the Regional Plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

7.2.2.1 Total Estimated Avoided Project Cost Benefit

The Estimated Avoided Project Cost Benefit for each Enrolled Transmission Provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may be displaced by a newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the Enrolled Transmission Providers that were allocated the costs for the previously-approved CEERTS project (see Attachment D, Example 4 for a hypothetical example of this cost allocation process).

Each Enrolled Transmission Provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.

The independent consultant will review each Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and ongoing capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of Enrolled Transmission Providers weighted by their total capitalization ("Enrolled TP Discount Rate"). Each Enrolled

Transmission Provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Avoided Project Cost Benefit" for each Enrolled Transmission Provider's displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

7.2.2.2 Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each Enrolled Transmission Provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under **Alternative Projects** in 7.2.1.

Each Enrolled Transmission Provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of Enrolled Transmission Providers weighted by their total capitalization ("Enrolled TP Discount Rate"). Each Enrolled Transmission Provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for each Enrolled Transmission Provider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

7.2.2.3 Total Estimated Transmission Line Loss Value Benefit

The Total Estimated Transmission Line Loss Value Benefit is calculated for each Enrolled Transmission Provider by the independent consultant as follows:

The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will direct the RPS to run simulations of the approved Regional Plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see **Alternative Projects** in 7.2.1), to establish base transmission losses for each Enrolled Transmission Provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and off-peak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see BTPP Step 3, Section A.4.a), after verifying that all reliability requirements are met, with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each Enrolled Transmission Provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled Transmission Providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each Enrolled Transmission Provider.

The value of the change in losses for each Enrolled Transmission Provider will be determined by the independent consultant as follows:

- The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses.
- The net present value of the value of losses will be determined for each Enrolled Transmission Provider using the Enrolled TP Discount Rate.
- Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit."

The TP Estimated Transmission Line Loss Value Benefit for each Enrolled Transmission Provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

7.2.2.4 Estimated CEERTS Project Cost

The Estimated CEERTS Project Cost is determined using the following formula:

Estimated CEERTS Project Cost = (a) Estimated Developer Cost + (b) Total Estimated Related Local Project Costs + (c) Total Estimated Displacement Costs

(a) The Estimated Developer Cost will be determined by the independent consultant as follows:

The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service.

The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

(b) The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant:

Each Enrolled Transmission Provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service.

The independent consultant will review the Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Related Local Project Cost.

All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost.

(c) The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows:

Any Enrolled Transmission Provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent consultant will estimate the level of displacement costs that the Enrolled Transmission Provider that has expended funds on a displaced project will recover by assuming that the Enrolled Transmission Provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost.

All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS Project Sponsors and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), this report will include an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 7.3 below. The CEERTS Project Sponsor and stakeholders shall be given an opportunity to provide written comments on the report to the Board. The CEERTS Project Sponsor shall be invited to be present and participate in any Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS Project Sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in Step 5 and in section 7.3 Public Policy Planning, as applicable.

F. If a CEERTS project is selected, the FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region.[5]

Step 6

With Board approval, Transmission Project Developer Selection process is initiated. CEERTS project selection finalized and included in FRCC Regional Plan

Over a period of two-to-three months following a decision that a CEERTS project should move forward under Step 5 of the BTPP, the following "Transmission Project Developer and Project Selection Process" will occur:

A. If the CEERTS project requires upgrades[6] to an Enrolled Transmission Provider's existing facilities, that Enrolled Transmission Provider retains a right of first refusal to build those portions of the CEERTS project.

B. If a single Project Sponsor is also the developer identified for a given CEERTS project, then that Project Sponsor/Developer is accepted by default as the Project Developer eligible to use the regional cost allocation for that CEERTS project (subject to the qualifications review below). If there are different proposed CEERTS projects to address the same transmission need(s), then the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in Step 5C, and once a Project Sponsor's/Developer's proposed CEERTS project is selected in the regional transmission plan, that Project Sponsor/Developer will also be selected as the Project Developer eligible to use the regional cost allocation for that CEERTS project. CEERTS projects proposed by

[5] Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC's CEERTS Cost: The costs associated with any required upgrades identified through the FRCC's CEERTS project evaluation process identified in Step 5F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this RTPP prevents the beneficiaries or Project Sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region.

[6] As used in this section the term "upgrade" means an improvement to, addition to, or replacement of a part of an existing transmission facility; the term does not refer to an entirely new transmission facility. Nothing herein affects an Enrolled Transmission Provider's rights under state law with regard to its real property (including rights-of-way and easements).

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a single qualified Project Developer and selected by the FRCC Board will not be assigned to a different Project Developer.

C. If there are multiple Project Developers for the same CEERTS project, then the FRCC Board will, upon request, facilitate an opportunity for the Project Sponsors/Developers to collaborate with each other to determine how each of the Project Developers may share responsibility for portions of the CEERTS project(s). If agreement is reached, then these Project Sponsors/Developers will be selected (subject to the qualifications review in Attachment B). If there is no agreement, then the Project Developer for the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in Step 5C.

Approval and Certification after Conclusion of the Project Developer Determination and Qualifications Review

At the next Board meeting after successful completion of the items in the steps 1 through 6C above and the Project Developer Determination and Qualification Review (Attachment B), the Board will notify the Project Developer to proceed with the project as it has been approved for inclusion in the regional transmission plan. It is at this point that any transmission projects currently in the regional transmission plan that are being avoided due to the new CEERTS project will be removed from the regional transmission plan and associated regional models. The Project Developer(s) shall then proceed with obtaining the necessary approvals and/or permits required to construct, own and operate the project including certification under the Florida Transmission Line Siting Act.

Process Summary

As identified in this BTPP process, proposed new CEERTS projects are to be submitted by June 1st of the first year of each biennial regional project's planning cycle. The technical evaluation of a new CEERTS project will occur within approximately 12 months concurrent with the evaluation of the initial FRCC regional transmission plan, and final approval will be achieved within 19 months. This time period may be shorter for some CEERTS projects, such as where the project is relatively small in scale.

Following the evaluation steps identified in this BTPP process for a newly proposed CEERTS project, a Project Sponsor can expect the project to be analyzed with the regional transmission plan in the summer or fall of the following year. For the project to remain in the regional transmission plan, the remainder of the process must be completed. For example, a new CEERTS project that was proposed by June 1st in the biennial year 1 would proceed through Step 3 in the fall of biennial year 1 through the winter of biennial year 2. In the following spring and summer of biennial year 2, the project would progress through the items in Step 5 and be added to the regional transmission plan. Successful completion of the items in Step 5 would qualify the project for final approval in December of biennial year 2, roughly 19 months after it was initially proposed.

This overall schedule provides a roadmap of the projected schedule for new CEERTS' project evaluation, selection, approval and ultimate reflection in the regional transmission plan within the mandatory two-year (biennial) planning cycle. A particular CEERTS project submittal may benefit from schedule flexibility or shortening of process steps depending on the project's nature or complexity, availability of qualified Project Developer(s), or other factors. In all cases, once a

CEERTS project is submitted, the FRCC will keep all parties informed of the projected schedule for project evaluation.

This CEERTS project evaluation process will fold into the overall regional transmission planning cycle, which will continue to be an annual process, that is, a regional transmission plan will continue to be developed each year. The inclusion of the CEERTS projects into the annual regional transmission plan will be in accordance with the process outlined above.

After a CEERTS project is approved for the regional transmission plan, the Project Developer shall submit to the FRCC PC a development schedule that sets forth the required steps necessary to develop and construct the project and the schedule that the developer will follow to satisfy each required step. Required steps include, but are not limited to, obtaining all regulatory approvals necessary to develop and construct the facility.

Status updates of a CEERTS project are required to the FRCC PC at any time when material changes to the project or schedule take place, or at least annually, and must include any revised cost estimate. If the cost estimate for a CEERTS project is substantially more than the cost estimate upon which the project was approved, the FRCC PC and Board may re-examine the cost effectiveness of the project.

If a CEERTS reliability-based project is abandoned by the developer, the transmission provider(s) has a right of first refusal to complete the project to the extent it is located in the transmission provider's service territory. However, if the transmission provider decides not to complete the abandoned reliability-based CEERTS project and decides instead to propose an alternative CEERTS project, then other potential developers will be given an opportunity to propose an alternative CEERTS project to ensure that the reliability need is met. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed. If a non-reliability-based CEERTS project is abandoned by the developer, other potential developers may offer to complete the project. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed.

If a delay in the completion of a CEERTS reliability-based project potentially would cause a transmission provider or other NERC-registered entity to violate a Reliability Standard, the NERC-registered entity shall inform the FRCC PC as soon as it is aware of the possibility. The FRCC PC will re-evaluate the regional transmission plan to determine if the delay in the CEERTS project requires the evaluation of alternative solutions to ensure the relevant transmission provider or other NERC-registered entity can continue to meet its reliability and/or other service obligations. If the FRCC PC determines that the delay in the CEERTS project would adversely affect reliability (e.g., would cause a violation of one or more NERC reliability standards), the FRCC PC will initiate a process to evaluate solutions to address the reliability concerns.

The transmission providers whose system(s) are affected by these reliability concerns will be given an opportunity to propose solutions that they would implement within their service territories or footprints to address these reliability concerns and their proposals can be evaluated as possible CEERTS projects if such transmission providers agree. The FRCC PC will fully evaluate the original CEERTS project delay along with any proposals for alternate solutions and will make a determination on how to proceed in a timely manner to ensure that the FRCC Regional Plan supports the adequate planning for a reliable transmission system for the FRCC region. Where possible, the review of a CEERTS project delay will be included within the BTPP cycle. However, if the FRCC PC determines that a CEERTS project delay needs to be evaluated outside of the BTPP cycle, the FRCC PC will notify the members and establish a schedule for the evaluation process. The FRCC PC will follow similar steps as described above to develop a report of the results of their evaluation and provide their findings to the Board for ultimate resolution.

The FRCC PC, under the oversight of the Board, will verify that all required reliability, operational, and property rights provisions listed below are in place, or reasonably planned for, after a CEERTS project is included in the Regional Plan. The Board will monitor such elements and progress toward such elements in determining whether a CEERTS project has been delayed or abandoned, including:

- All certification and other requirements under the NERC Standards and Rules of Procedure;
- Implementation of communications and operational control features (e.g., requirements to follow instructions of the Reliability Coordinator, Balancing Authority and/or Transmission Service Provider);
- Responsibility for operation and maintenance ("O&M"), including any plans to turn over O&M responsibilities to another entity; and
- Acquisition of the property rights necessary to construct the CEERTS facilities, or a reasonable expectation of the ability to acquire such rights.

7.3 Public Policy Planning

To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the FRCC PC, prior to January 1st of the first year of the BTPP cycle for consideration in regional planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should:

- identify the state, federal, or local law or regulation that contains the public policy requirement;
- identify the type of entity(ies) in the region to which the public policy requirement applies;
- identify the subset of entities in the region subject to the public policy requirement that have a transmission need driven by the public policy requirement;
- describe the type and nature of the transmission service, including the number of megawatts, needed from the Enrolled Transmission Providers by such subset of entities, to meet that transmission need.

Any stakeholder submitting a potential public policy transmission need to the FRCC PC may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need. All submissions will be posted on the FRCC website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required. The FRCC PC, under the oversight of the Board, may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post its determination on the FRCC website prior to March 1st of the first year of the BTPP cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a transmission solution is required, CEERTS and local projects shall be proposed as part of the BTPP to address such a need.

8.0 Interregional Transmission Coordination Procedures

The FRCC through this RTPP, coordinates with the public utility transmission providers in the Southeastern Regional Transmission Planning process region ("SERTP") to address transmission planning coordination issues related to interregional transmission facilities. These Interregional Transmission Coordination Procedures ("ITCP") include a detailed description of the process for coordination between the FRCC and the SERTP (on behalf of the public utility transmission providers); (i) with respect to an interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than transmission facilities included in the regions' respective regional transmission plans. The ITCP are provided in this RTPP with additional materials provided on the regional planning websites.

The following requirements are included in the ITCP:

(1) A commitment to coordinate and share the results of the FRCC and SERTP regional transmission plans to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) A duty to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The transmission providers in the FRCC have worked with transmission providers located in the SERTP to develop a mutually agreeable method for allocating between the two transmission planning regions the costs of new interregional transmission facilities that are located within both transmission planning regions. Such cost allocation method satisfies the six interregional cost allocation principles set forth in Order No. 1000 as approved by the FERC and is included in this RTPP.

Interregional Transmission Planning Principles

Representatives of the FRCC and the SERTP will meet no less than once per year to facilitate the ITCP described below (as applicable). Representatives of the FRCC and the SERTP may meet more frequently during the evaluation of project(s) proposed for purposes of interregional cost allocation between the FRCC and the SERTP.

8.1 Coordination

8.1.1 **Review of Respective Regional Plans:** Biennially, the FRCC and the SERTP shall review each other's current regional plan(s) and engage in the data exchange and joint evaluation described in Sections 8.2 and 8.3.

8.1.2 **Review of Proposed Interregional Projects:** The FRCC and SERTP will coordinate with regard to the evaluation of interregional transmission projects identified by the FRCC and SERTP as well as interregional transmission projects proposed for Interregional Cost

Allocation Purposes ("Interregional CAP"), pursuant to Sections 8.3 and 8.4, below. Initial coordination activities regarding new interregional proposals will typically begin during the third calendar quarter. The FRCC and the SERTP will typically exchange status updates for new interregional transmission project proposals or proposals currently under consideration every six (6) months, or as needed. These status updates will generally include, if applicable:

- an update of the region's evaluation of the proposal;
- the latest calculation of Regional Benefits (as defined in Section 8.4.2);
- the anticipated timeline for future assessments; and
- re-evaluations related to the proposal.

8.1.3 **Coordination of Assumptions Used in Joint Evaluation:** The FRCC and SERTP will coordinate assumptions used in joint evaluations, as necessary, which includes items such as:

- Expected timelines/milestones associated with the joint evaluation;
- Study assumptions; and
- Regional benefit calculations.

8.2 Data Exchange

8.2.1 At least annually, the FRCC and the SERTP shall exchange power-flow models and associated data used in the regional transmission planning processes to develop their respective then-current regional transmission plan(s). This exchange will typically occur by the beginning of each region's transmission planning cycle. Additional transmission-based models and data may be exchanged between the FRCC and SERTP as necessary and if requested. For purposes of the interregional coordination activities outlined in this RTPP, only data and models used in the development of the FRCC's and SERTP's then-current regional transmission plans and used in their respective regional transmission planning processes will be exchanged. This data will be posted on the pertinent regional transmission planning process' website, consistent with the posting requirements of the respective regional transmission planning processes, and is considered CEII. The FRCC shall notify the SERTP of such posting.

8.2.2 The FRCC regional transmission plans will be posted on the FRCC website pursuant to the FRCC's RTPP. The FRCC will also notify the SERTP of such posting so the public utility transmission providers in the SERTP may retrieve these transmission plans. The SERTP will exchange their then-current SERTP regional plan(s) in a similar manner to the FRCC according to their regional transmission planning process.

8.3 Joint Evaluation

8.3.1 **Identification of Interregional Projects:** After the FRCC and SERTP have exchanged planning models and data and current regional transmission plans as described in Section 8.2, the FRCC and, the SERTP will review one another's then-current regional plan(s) in accordance with the coordination procedures described in Section 8.1 and their respective regional transmission planning processes. If through this review, the FRCC or SERTP identify a potential interregional project that could be more efficient or cost effective than projects included in the respective regional plans, the FRCC and SERTP will jointly evaluate the potential project pursuant to Section 8.3.4.

8.3.2 **Identification of Interregional Projects by Stakeholders:** Stakeholders may also propose projects that may be more efficient or cost-effective than projects included in the FRCC's and the SERTP's regional transmission plans pursuant to the procedures in each region's regional transmission planning processes. The FRCC and the SERTP will evaluate interregional projects proposed by stakeholders pursuant to Section 8.3.4.

8.3.3 **Identification of Interregional Projects by Developers**: Interregional transmission projects proposed for potential Interregional CAP must be submitted in both the SERTP and FRCC regional transmission planning processes. The project submittal must satisfy the requirements of Section 8.4.1. The submittal must identify the potential transmission project as interregional in scope and identify the FRCC and SERTP as regions in which the project is proposed to interconnect. The FRCC will verify whether the submittal for the potential interregional transmission project satisfies all applicable requirements. Upon finding that the proposed interregional transmission project satisfies all such applicable requirements, the FRCC will notify the public utility transmission providers in the SERTP. Once the potential project has been proposed through the regional transmission planning processes in both regions, and upon both regions so notifying one another that the project is eligible for consideration pursuant to their respective regional transmission planning processes, the FRCC and SERTP will jointly evaluate the proposed interregional projects pursuant to Sections 8.3 and 8.4.

8.3.4 **Evaluation of Interregional Projects:** The FRCC and the SERTP shall act through their respective regional transmission planning processes to evaluate potential interregional transmission projects and to determine whether the inclusion of any potential interregional transmission projects in each region's regional transmission plan would be more efficient or cost-effective than projects included in their respective then-current regional transmission plans. Such analysis shall be consistent with accepted planning practices of the respective regions and the transmission study methodologies utilized to produce each region's respective regional transmission plan(s). The FRCC will evaluate potential interregional transmission projects consistent with the BTPP. To the extent possible and as needed, assumptions and models will be coordinated between the FRCC and SERTP as described in Section 8.1. Data exchange to facilitate this evaluation shall use the procedures described in Section 8.2.

8.3.5 **Initial Evaluation of Interregional Projects Proposed for Interregional Cost Allocation Purposes:** If an interregional project is proposed in the FRCC and the SERTP for Interregional CAP, the initial evaluation of the project will typically begin during the third calendar quarter, with analysis conducted in the same manner as analysis of interregional projects identified pursuant to Sections 8.3.1 and 8.3.2. Projects proposed for Interregional CAP shall also be subject to the requirements of Section 8.4.

8.4 Cost Allocation

If an interregional project is proposed for Interregional CAP in the FRCC and the SERTP, then the following methodology applies:

8.4.1 **Interregional Projects Proposed for Interregional Cost Allocation Purposes:** For a transmission project to be considered for Interregional CAP within the FRCC and the SERTP, the following criteria must be met:

A. The transmission project must be interregional in nature;
   - Be located in both the FRCC and the SERTP regions;
   - Interconnect to transmission facilities in both the FRCC and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan(s) that are currently under development; and
   - Meet the threshold criteria for transmission projects potentially eligible to be included in the regional transmission plans for purposes of cost allocation in both the FRCC and the SERTP, pursuant to their respective regional transmission planning processes.

B. On a case-by-case basis, the FRCC and the SERTP will consider a transmission project that does not satisfy all of the criteria specified in Section 8.4.1.A but: (i) meets the threshold criteria for a project proposed to be included in the regional transmission plan for purposes of cost allocation in at least one of the two regions; (ii) would be located in both regions; and (iii) would be interconnected to transmission facilities in both the FRCC and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan that are currently under development.

C. The transmission project must be proposed for purposes of cost allocation in both the FRCC and the SERTP.
   - Except for the case-by-case exception for project threshold criteria identified in Section 8.4.1.B, the transmission developer and project submittal must satisfy all criteria specified in the respective regional transmission processes.

8.4.2 **Evaluation of Interregional Projects Proposed for Interregional Cost Allocation Purposes:** Interregional projects proposed for Interregional CAP in the FRCC and the SERTP shall be evaluated within the respective regions as follows:

A. Each region, acting through its regional transmission planning process, will evaluate proposals to determine whether the proposed project(s) addresses transmission needs that are currently being addressed with projects in its regional transmission plan and, if so, which projects in the regional transmission plan could be displaced by the proposed project(s).

B. Based upon its evaluation, each region will quantify a Regional Benefit based upon the transmission costs that each region is projected to avoid due to its transmission project(s) being displaced by the proposal.

- For purposes of this ITCP, "Regional Benefit" means the total avoided costs of projects included in the then-current regional transmission plans that would be displaced if the proposed interregional transmission project was included. The Regional Benefit is not necessarily the same as the benefits used for purposes of *regional* cost allocation.

8.4.3 **Calculation of Benefit- to- Cost Ratio:** Each region will calculate a regional benefit-to-cost ("BTC") ratio consistent with its regional process and compare the BTC ratio to its respective threshold to determine if the interregional project appears to be more efficient or cost effective than those projects included in its current regional transmission plan. Each region shall utilize the cost calculation(s) as defined in such region's regional transmission planning process (*e.g.,* the FRCC will compute the cost of the portion of the interregional project that resides within the FRCC region in accordance with their regional process and the SERTP will do the same). The regions shall also coordinate such cost calculation assumptions in accordance with Section 8.1.3. The anticipated percentage allocation of costs of the interregional project to each region shall be based upon the ratio of the region's Regional Benefit to the sum of the Regional Benefits identified for both the FRCC and the SERTP. The Regional Benefits shall be determined pursuant to the methodology described in Section 8.4.2. Regional BTC assessments shall be performed in accordance with each region's regional transmission planning process, including but not limited to subsequent calculations and reevaluations.

8.4.4 **Inclusion in Regional Transmission Plans:** An interregional project proposed for Interregional CAP in the FRCC and the SERTP will be included in the respective regional transmission plans for purposes of cost allocation after:

A. Each region has performed all evaluations, as prescribed in its regional transmission planning process, necessary for a project to be included in its regional transmission plan for purposes of cost allocation;
   - This includes any regional BTC ratio calculations performed pursuant to Section 8.4.3; and

B. Each region has obtained all approvals, as prescribed in its regional process, necessary for a project to be included in the regional transmission plan for purposes of cost allocation.

8.4.5 **Allocation of Costs Between the FRCC and the SERTP:** The cost of an interregional project, selected for purposes of cost allocation in the regional transmission plans of both the FRCC and the SERTP, will be allocated as follows:

A. Each region will be allocated a portion of the interregional project's costs in proportion to such region's Regional Benefit to the sum of the Regional Benefits identified for both the FRCC and the SERTP.

   - The Regional Benefits used for this determination shall be based upon the last Regional Benefit calculation performed – pursuant to the method described in Section 8.4.2. – before each region included the project in its regional transmission plan for purposes of cost allocation and as approved by each region.

B. Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in its regional transmission planning process.

C. Should one region be willing to bear more costs of the interregional transmission project than those costs identified pursuant to the methodology described in Section 8.4.5.A, the regions may voluntarily agree, subject to each regions and the affected transmission providers' approvals, to an alternative cost-sharing arrangement.

8.4.6 **Removal from Regional Plans:** An interregional project may be removed from the FRCC's or the SERTP's regional transmission plan for purposes of cost allocation: (i) if the developer fails to meet developmental milestones; (ii) pursuant to the reevaluation procedures specified in the respective regional transmission planning processes; or (iii) if the project is removed from one of the region's regional transmission plans pursuant to the requirements of its regional transmission planning process.

A. The FRCC shall notify the public utility transmission providers in the SERTP if an interregional project or a portion thereof is likely to be removed from its regional transmission plan.

8.5 Openness and Transparency

The FRCC shall follow the principles enumerated in Section 6.0 of this RTPP. In addition, the FRCC shall perform the following additional tasks for interregional planning:

A. Access to the interregional planning data utilized will be made available through the FRCC website subject to the Standards of Conduct Protocols. The FRCC shall make available on the FRCC website links to where SERTP and its stakeholders can register and obtain necessary agreements for access to FRCC data and documents.

B. The FRCC will provide status updates of the interregional transmission planning activities during their regional transmission planning meetings, FRCC Board meetings and at the FRCC PC meetings. The status updates of interregional activities will include at a minimum:
   - Facilities to be evaluated;
   - Analysis performed; and
   - Determinations/results.

C. FRCC members and stakeholders will have an opportunity to participate and provide input and feedback in either or both of the respective regional transmission planning processes and coordination related to interregional facilities identified, analysis performed, and any determinations/results.

D. The FRCC will post, on the FRCC website, a list of all interregional transmission projects that are proposed for potential selection in a regional transmission plan for purposes of cost allocation in both the FRCC and the SERTP that are found not to be eligible for consideration because they do not satisfy the regional project threshold criteria of one or both of the regions. The FRCC will also post an explanation of the relevant thresholds the proposed interregional project(s) failed to satisfy.

9.0 Document Distribution/Notification Requirements

9.1 Distribution/Notification Timeframe

This document should be distributed within 5 business days of version approval. It shall also be posted publicly on the FRCC website for Order No. 1000 stakeholders.

9.2 NERC Required Distribution/Notification List

None

9.3 Additional Distribution/Notification List

Planning Committee

Regional Projects Subcommittees

Transmission Technical Subcommittee

10.0 References

10.1 *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests (FRCC-MS-PL-054)*

10.2 *FERC Standards of Conduct Protocols for the FRCC*

10.3 *Rules of Procedure for FRCC Standing Committees*

10.4 *Request for FRCC Transmission Information*

10.5 *FRCC Load Flow & Short Circuit Data Bank Procedural Manual (FRCC-MS-PL-029)*

11.0 List of Attachments

Attachment A: Sharing of Certain Transmission Expansion Costs

Attachment B: Project Developer Qualification Criteria and Review

Attachment C: Map

Attachment D: Examples of CEERTS Cost Allocation Methodology

12.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
10/07/2014	1	New Document incorporating existing FRCC Regional Transmission Planning Process with FERC Order 1000	All
10/29/2014	1	FRCC Board of Directors Approval	All
1/23/2015	2	Revised due to OATT update	All
9/18/2015	3	Revised due to final FERC approval of OATT changes for both Regional Planning and Interregional Coordination. Also aligned RTPP with principles as outlined in the OATTs.	All
9/18/2017	4	Updated references from SWG, TWG and RWG to SAS, TTS and RS respectively and updated the GISR process document reference. Added minor grammatical and capitalization edits. Added new document classification verbiage to cover page. Removed classification and effective date fields from page 2.	All
04/07/2020	5	Periodic review. Minor clarifications consistent with member tariff wording	Sec. 6.2.4 and 6.4.3
04/07/2022	6	Periodic review. No substantive edits needed. Update to FRCC address on title page and addition of Document Distribution requirements per latest FRCC Document Control Policy.	Title page and 9.0
08/28/2024	7	Periodic review. No edits.	All

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Attachment A: Sharing of Certain Transmission Expansion Costs

The cost allocation provisions contained in this Attachment A relate to cost allocation procedures for specific circumstances as described herein. This document sets forth (i) certain principles regarding the provision of financial funding to Transmission Owners that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of other Transmission Owners (third-party impacts), (ii) the principles to allocate the cost of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, and (iii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. This document shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to either FERC Order 2003 or Order 2006.

Cost Allocation for Third-Party Impacts resulting from the FRCC RTPP

FRCC Principles

1. Except for a CEERTS project for which it is not the Project Developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC and FRCC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole and FMPA), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

2. If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter "Precipitating Events"), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner's system shall hereinafter be referred to as the "Remedial Upgrade." Upgrade(s), expansion(s), or provisions of service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:
   - A new generating unit(s) to serve incremental load
   - A new or increased long-term sale(s)/purchase(s) to or by others (different uses)
   - A new or modified long-term designation of Network Resource(s)
   - A new or increased long-term, firm reservation for point-to-point transmission service

   Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the threshold criteria described in Principle 5.a. shown below. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

3. Except for a CEERTS project for which it is not the Project Developer and except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

4. Except for a CEERTS project for which it is not the Project Developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

5. Threshold Criteria: The following criteria ("Threshold Criteria") must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade:

   a. The need for the Remedial Upgrade must result, or have resulted, from a Precipitating Event that causes a change in power flow of at least a 5% or 25 MW, whichever is greater, on a facility of the Affected Transmission Owner that, but for the Remedial Upgrade, is reasonably expected to result in a violation of applicable NERC and FRCC Reliability Standards, as determined through the FRCC RTPP.

   b. All new or upgraded transmission facilities comprising the Remedial Upgrade must have an operating voltage of 230 kV or higher voltage.

   c. The Upgrade Costs of the Remedial Upgrade must exceed $3.5 million. As used herein, the "Upgrade Costs" means the construction costs of the Remedial Upgrade (determined in accordance with FERC's Uniform System of Accounts) plus the identifiable Pre-Construction Costs thereof. As used herein, "Pre-Construction Costs" are costs that are expended in preparation for the construction of a transmission project, incurred up to and including the date the utility completes site-clearing work. Pre-Construction Costs include, but are not limited to: any and all costs associated with preparing, reviewing and defending an application under the Transmission Line Siting Act (TLSA); costs of site, technology and route selection and acquisition; costs of engineering, designing, and permitting; costs of clearing, grading, and excavation; and costs of development of any on-site construction facilities.

6. In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must (i) participate, directly or indirectly, in the FRCC RTPP, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.
7. The following principles govern the nature and amount of Financial Assistance that an Affected

Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade:

a. In the event that it is reasonably determined that the Remedial Upgrade eliminates or defers the need for another transmission upgrade or expansion, then, for purposes of paragraphs 7.b and 7.c below, the Upgrade Costs of the Remedial Upgrade shall be reduced by the reasonably determined net present value of such other upgrade or expansion that will be avoided as a result of the Remedial Upgrade ("Avoided Costs") up to the amount of the net present value of the total cost of the Remedial Upgrade. If, in such event, the Transmission Owner(s) experiencing such Avoided Costs is/are not the Affected Transmission Owner, the Affected Transmission Owner shall be entitled to receive payment from such other Transmission Owner(s) equal to such net present value. The remaining Upgrade Costs of the Remedial Upgrade (i.e., the Upgrade Costs less, if applicable, the Avoided Costs of all Transmission Owners, including the Affected Transmission Owner, in the Transmission Zone; hereinafter the "Net Upgrade Costs") would be allocated 50% to parties in the Transmission Zone in which the Remedial Upgrade occurred on a weighted basis based upon load[1] (see item 7.b. below), and 50% based upon sources of power (see item 7.c. below).

b. The Affected Transmission Owner shall be entitled to receive from other Transmission Owners having load within the Transmission Zone in which the Remedial Upgrade is to be made a payment in an amount equal to (i) 50% of the Net Upgrade Costs of the Remedial Upgrade[2] times (ii) each Transmission Owner's Load Ratio within that Transmission Zone. Such Load Ratio shall be the ratio of the amount in MW of the load served by each Transmission Owner in the Transmission Zone to the sum in MW of all load in that same Transmission Zone.[3] (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs).

Initially, there are six Transmission Zones in the FRCC region, as depicted in Attachment C. These Transmission Zones are subject to modification in the future in specific instances to the extent warranted by circumstances. A request by a party to modify one or more Transmission Zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability).

The following principles will guide how the boundaries of Transmission Zones are determined:
- Electrically, a substantial amount of the generation within a Transmission Zone is used to serve load also within that Transmission Zone.
- Transmission facilities in a Transmission Zone are substantially electrically independent of other Transmission Zones.
- Transmission Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.
- Transmission Zones may be modified by providing a technical showing with the supporting

[1] 100% if transmission expansion not precipitated by a transmission request keyed to sources of power (i.e., generation).
[2] See note 2 above regarding the applicable percentage.
[3] Load refers to the projected average of individual system winter and summer peak loads for all years of the study horizon (e.g., the average of ten values for a five-year study period).

rationale to the FRCC PC for its review and approval. An example of a potential need for a zone change may be that, in order to mitigate an overloaded facility, a transmission upgrade or expansion would extend beyond the pre-established zonal boundaries such that these boundaries would need to be revised to best address this situation.

c. If the Remedial Upgrade shall have been precipitated by one or more transmission service requests keyed to new sources of power (i.e., generation), then the party(ies) requesting such transmission service(s) shall be responsible for providing to the Affected Transmission Owner funding for 50% of the Net Upgrade Costs of the Remedial Upgrade in proportion to the respective Source Ratios. Each Source Ratio shall be a ratio of the amount in MW of the associated incremental resource's flow impact affecting the limiting facility that caused the need for the Remedial Upgrade to the sum in MW of the total flow impact of all such new resources. The incremental resource's flow impact shall be calculated with the new resource at full output, at peak load level, without contingencies, and averaged over the study period.

   If studies determine that multiple transmission service requests keyed to new sources of power contribute to the need for a Remedial Upgrade by an Affected Transmission Owner, a coordinated study will be performed assessing all such sources of power in a cluster type approach. The transmission customers that confirm the associated transmission reservations for those new sources of power will share in the cost responsibility for these Remedial Upgrades.

   Funding of Upgrade Costs provided by a party to an Affected Transmission Owner in accordance with this paragraph 7.c shall be subject to repayment, without interest, by the Affected Transmission Owner as follows: First, during the first ten years following the completion of the Remedial Upgrade, a funding party shall be entitled to receive credits from the Affected Transmission Owner against charges for transmission services provided by the Affected Transmission Owner to that party, up to the value of the funding party's contribution. Such credits will apply to all charges throughout the ten-year period for any uses of transmission services by the funding party of the Affected Transmission Owner's transmission system. Second, at the end of the ten-year period, the Affected Transmission Owner shall repay the funding party the balance (i.e., Upgrade Costs of such party less amounts for which credits shall have been provided), if any, of the amount provided by that party, without interest.

8. Implementation and Dispute Resolution Process:

   a. As soon as practical after a Transmission Owner shall have identified itself as an Affected Transmission Owner because of the need for a Remedial Upgrade, that Transmission Owner and parties whose actions shall have contributed, or are reasonably expected to contribute, to the need for that Remedial Upgrade and which may be responsible for providing Financial Assistance in connection therewith in accordance herewith shall enter into good faith negotiations to (i) confirm the need and cause for the Remedial Upgrade and their respective responsibilities for providing Financial Assistance to the Affected Transmission Owner, and (ii) establish a fair and reasonable schedule and means by which such Financial Assistance is to be provided to the Affected Transmission Owner.

   b. In the event the parties identified in the foregoing paragraph are unable to reach agreement on the determination or assignment of cost responsibility within a sixty-(60) day period, the dispute shall be resolved pursuant to the Dispute Resolution Procedures in the FRCC Bylaws.

c. Nothing in this document is intended to abrogate or mitigate any rights a party may have before any regulatory or other body having jurisdiction.

d. During those circumstances in which this section 8 pertaining to Dispute Resolution Process is being utilized due to parties being unable to reach agreement on the determination or assignment of cost responsibility associated with a Remedial Upgrade(s), the parties shall continue in parallel with the Dispute Resolution Process and the engineering, permitting and siting associated with the Remedial Upgrade(s). The fact that a matter is subject to Dispute Resolution hereunder shall not be a basis for any party being relieved of its obligations under this document.

Cost Allocation for CEERTS Projects

There are three potential sets of CEERTS' project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS Project Developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

1. Project beneficiaries for a CEERTS project will be transmission providers within the FRCC region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

2. The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in Step 5 of the BTPP: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable. Examples of CEERTS project cost allocation are provided in Attachment D, Examples 1 and 2.

3. The costs for CEERTS public policy projects, that are identified through the process described in the "Public Policy Planning" section 7.3 of the RTPP, will be allocated to the Enrolled Transmission Providers whose transmission systems provide access to the public policy resources. The cost allocation for each Enrolled Transmission Provider will be as follows:

   • Individual Enrolled Transmission Provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory.

• Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

• Individual Enrolled Transmission Provider cost allocation percentage = (Individual Enrolled Transmission Provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Attachment D, Example 3. These percentages will be used to allocate actual CEERTS' project costs that are recoverable.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

Allocation of Transmission Rights

Enrolled Transmission Providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to a transmission provider, including use by the transmission provider itself, shall be governed by the transmission provider's Tariff.

Attachment B: Project Developer Qualification Criteria and Review

Project Developer Qualification Criteria and Review

Developers seeking to be qualified to be a CEERTS Project Developer must submit information to demonstrate that they satisfy the qualification criteria so that the Board can review the qualifications and make a determination as to whether a prospective transmission developer satisfies the qualification criteria such that it may propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

Project Developer Qualification Criteria

1. Demonstration that the Project Developer is technically, and financially capable of (i) completing the CEERTS project in a timely and competent manner; and (ii) operating and maintaining the CEERTS facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. To support this demonstration, the following information should be provided/shown:

   A. Project Developer's current and expected capability to finance, or arrange financing for the transmission facilities:

      1. Evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financing structure of such projects, a description of any financing obtained for these projects through any approved rates, the financing closing date of such project, and whether any of the projects are in default;
      2. Its audited financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;
      3. Current credit ratings from Moody's Investor Services and Standard & Poor's, if available;
      4. A summary of any history of bankruptcy, dissolution, merger, or acquisition of the Project Developer or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of information related to affiliated entities;
      5. A summary of outstanding liens against the developer(s); and
      6. Such other evidence that demonstrates its current and expected capability to finance a CEERTS project.

      The Project Developer must identify the portions of this financial data that would need to be treated as confidential information in accordance with the FRCC confidentiality practices and subject to disclosure only to those that have signed a confidentiality agreement.

   B. Total dollar amount of CEERTS' estimated project(s) cost up to which the Project Developer wants to be deemed qualified.

   C. A discussion of the Project Developer's business practices that demonstrate that its business practices are consistent with Good Utility Practices for proper licensing, designing, right-of-way acquisition, constructing, operating and maintaining transmission facilities that will become part of the regional transmission grid. The Project Developer shall also provide the following information for the current calendar year and the previous five calendar years:

1. A summary of any violations of law by the Project Developer found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general; and
2. A summary of any instances in which the Project Developer is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

D. Technical and engineering qualifications and experience;

E. Past history of meeting transmission project schedules;

F. Past history regarding providing construction and maintenance of transmission facilities and/or contracting for the construction and maintenance of transmission facilities;

G. Capability to adhere to standardized construction, maintenance and operating practices;

H. Plans for compliance with all applicable reliability standards:

I. Planning standards that will be used to develop the project: and

J. Plans to obtain the appropriate NERC certifications.

2. An attestation from an officer of the Project Developer stating that the information that is being submitted is true and that the Project Developer will comply with the provisions identified in the qualification data submittal, and will submit a biennial (or more often if the information provided has materially changed) update of the information submitted, accompanied by an attestation from an officer of the Project Developer that the previously submitted information remains correct and has not materially changed since the last attestation, with such attestation to be submitted biennially while that transmission developer has a transmission project under consideration in the FRCC Regional Planning Process, under construction in the FRCC region or in-service within the FRCC region.

3. For joint ventures, partnerships, or other multiple-party developer arrangements, the qualification criteria above will be applied to the designated lead entity, which will be responsible for meeting the qualification criteria. Sharing of such responsibilities with other entities may be achieved contractually between the designated lead entity and its partners.

Project Developer Qualifications Review

1. Project Developers (both incumbent and non-incumbent Project Developers) that are submitting for the first time a qualification application must submit the application and a deposit of $50,000 to the FRCC along with the information identified in the Qualification Criteria as set forth in this Attachment B above. The deposit will be used by the Board to fund the internal FRCC labor cost for application

review, which will be documented, and expenses for the independent consultant for the review described in the next section. Any unexpended amounts from the deposit, including interest, shall be refunded to the Project Developer. The transmission developer will be provided with an accounting of the actual costs and how the costs were calculated. Any disputes related to the accounting for specific deposits shall be addressed under the dispute resolution procedures in the FRCC Bylaws. A Project Developer may be a joint venture or a partnership in which case a lead representative will be designated in the qualification application. Project Developers that already have been found qualified after a review by the FRCC must submit an attestation to maintain their qualification as discussed in above. If sufficient changes, as determined by the FRCC, have been identified in the attestation by a Project Developer which had previously been qualified, then a deposit of $10,000 to the FRCC will be required during the attestation review process. This deposit will be handled in a similar manner as described above for the initial Project Developer qualification review.

2. The Board will provide for the review of the submitted qualifications by an independent consultant. The independent consultant fees will be paid from the deposit made when a Project Developer qualification application is submitted. The independent consultant will make a recommendation to the Board as to whether the Qualification Criteria have been met. The Board shall make, on a non-discriminatory basis, a determination as to whether the Qualification Criteria have been met. If the Board determines that the Qualification Criteria have not been met, the Board will notify the Project Developer of the qualification deficiencies and provide a 30-day period for the Project Developer to cure the deficiencies. If a Project Developer does not agree with the Board's determination, then the FRCC Bylaws Dispute Resolution Procedures are available for use by the Project Developer. The qualification process is a one-time process for each Project Developer, subject to the attestation review process annual update.

3. The timeline for the Project Developer qualification review evaluation process is set forth below:

    a. By January 1st of the first year of a BTPP cycle, any potential developer that seeks to be qualified to develop CEERTS projects during this cycle must submit its qualifications to the FRCC. Biennial attestations also must be submitted at this time.

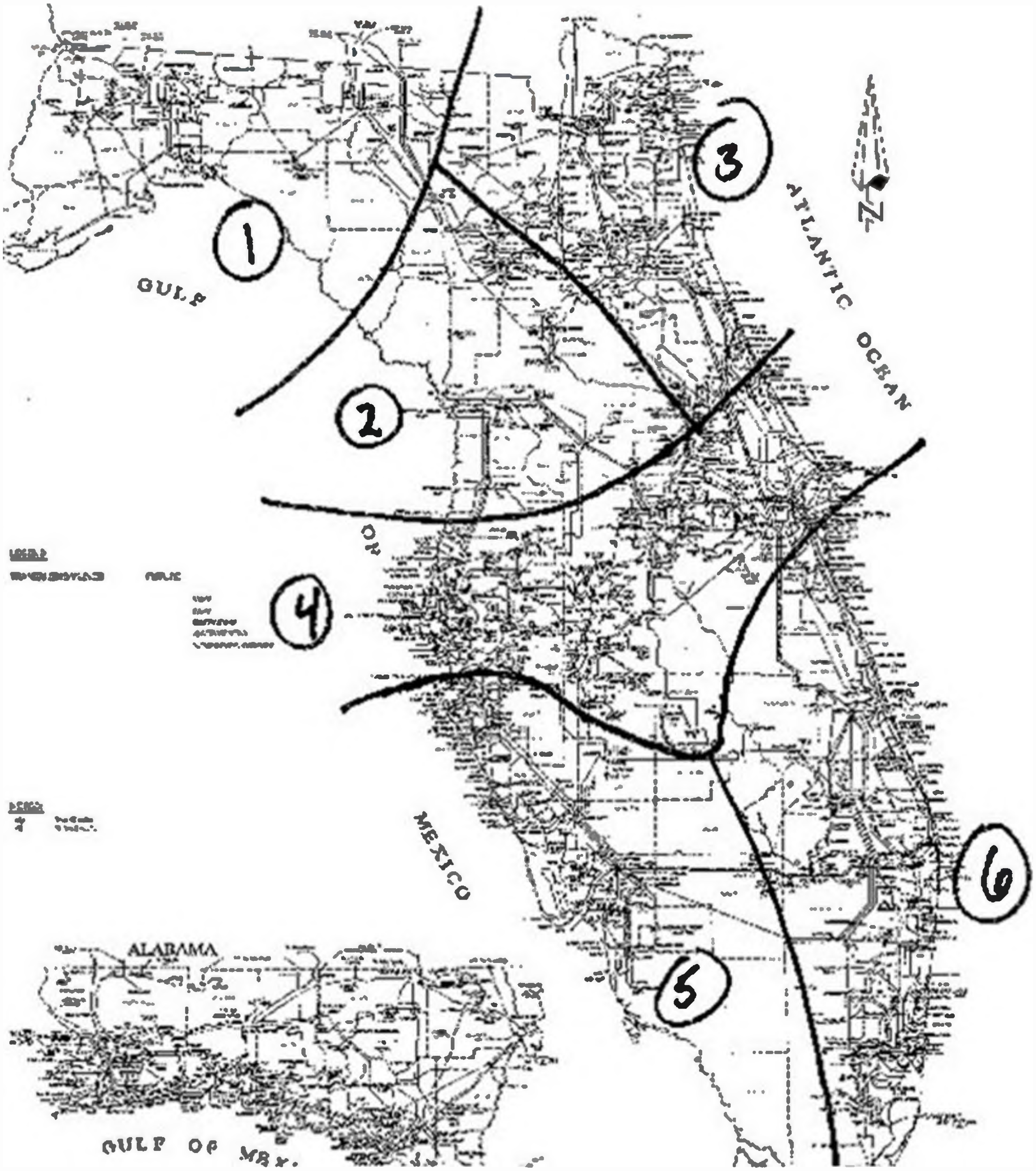
    b. In January through March of the first year of a BTPP cycle, FRCC shall coordinate the qualifications review.

    c. By April 1st of the first year of a BTPP cycle, the Board will inform developers that have submitted qualifications or attestations that they have either met the qualification criteria or the Board will identify deficiencies in the submitted qualifications/attestations.

    d. From April 1st through April 30th of the first year of a BTPP cycle, developers will have an opportunity to cure deficiencies and resubmit their modified qualifications/attestations.

    e. From May 1st through May 31st of the first year of a BTPP cycle, the Board shall reexamine the modified qualifications/attestations, make final determinations, and notify developers, FRCC members and other stakeholders.

Attachment C: Map



Attachment D: Examples of CEERTS Cost Allocation Methodology

Example 1: Reliability/Economic Project

CEERTS project where Enrolled Transmission Providers A, B and C all receive benefits from the project.

The Project Developer is a non-incumbent developer

Assumptions:

Estimated CEERTS Project Cost = $401M:

– Estimated Developer Cost = $400M

– Total Estimated Related Local Project Costs = $1M

Total Estimated Avoided Project Cost Benefit = $500M:

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $300M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200M

– Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $0

Total Estimated Alternative Project Cost Benefit = $0M

Total Estimated Transmission Line Loss Value Benefit = $14M:

– Enrolled Transmission Provider A Estimated Transmission Line Loss Value Benefit = $4M

– Enrolled Transmission Provider B Estimated Transmission Line Loss Value Benefit = $5M

– Enrolled Transmission Provider C Estimated Transmission Line Loss Value Benefit = $5M

Benefit to Cost Ratio:

“(Total Estimated Avoided Project Cost Benefit” ($500M) plus "Total Estimated Alternative

Project Cost Benefit" ($0M) plus “Total Estimated Transmission Line Loss Value Benefit” ($14M)) divided by Estimated CEERTS Project Cost ($401M) = 1.28, therefore this CEERTS project passes the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

(Percentages in this example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = (($300M + $4M) ÷ $514M) = 59%

– Enrolled Transmission Provider B = (($200M + $5M) ÷ $514M) = 40%

– Enrolled Transmission Provider C = (($0 + $5M) ÷ $514M) = 1%

Example 2: Reliability/Economic Project

CEERTS project where Enrolled Transmission Providers A & B each receive avoided cost benefits from the project.

There are no transmission loss benefits.

The Project Developer is a non-incumbent developer

Assumptions:

Estimated CEERTS Project Cost = $400 M:

– Estimated Developer Cost = $400 M

Total Estimated Avoided Project Cost Benefit = $300 M:

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $100 M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200 M

Total Estimated Alternative Project Cost Benefit = $0M

Benefit to Cost Ratio:

"Total Estimated Avoided Project Cost Benefit" ($300 M) divided by Estimated CEERTS Project Cost ($400 M) = 0.75, therefore this CEERTS project does not pass the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

– N/A

Example 3: Public Policy Project

CEERTS project where LSEs within Enrolled Transmission Providers A, B and C each receive benefits from the project.

The Project Developer is a non-incumbent developer.

Assumptions:

Public policy CEERTS project enables access to a total of 600 MW of public policy resources

Public policy CEERTS project enables LSEs within Enrolled Transmission Providers A, B and C to access the public policy resources:

– Enrolled Transmission Provider A = 100 MWs

– Enrolled Transmission Provider B = 200 MWs

– Enrolled Transmission Provider C = 300 MWs

CEERTS Project Cost Allocation:

(Percentages in this example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = (100 MW / 600 MW) = 17%

– Enrolled Transmission Provider B = (200 MW / 600 MW) = 33%

– Enrolled Transmission Provider C = (300 MW / 600 MW) = 50%

Example 4: Newly-Proposed CEERTS Project Displacing a Previously-Approved CEERTS Project

Previously-approved CEERTS project was estimated to provide LSEs within Enrolled Transmission Providers A and B benefits

Newly-proposed CEERTS project would displace the previously-approved CEERTS project as well as being estimated to provide LSEs within Enrolled Transmission Provider C benefits from the newly-proposed CEERTS project

The newly-proposed CEERTS project would displace the previously-approved CEERTS project

Previously-Approved CEERTS Project:

Assumptions:

Estimated Previously-Approved CEERTS Project Cost = $75M

Total Estimated Previously-Approved CEERTS Project Avoided Project Cost Benefit = $100M

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $50M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $50M

Previously-Approved CEERTS Project Cost Allocation:

(Percentages in example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = ($50M / $100M) = 50%

– Enrolled Transmission Provider B = ($50M / $100M) = 50%

Previously-Approved CEERTS Project Displaced by a Newly-Proposed CEERTS Project:

Assumptions:

Estimated Newly-Proposed CEERTS Project = $100M

Total Estimated Newly-Proposed CEERTS Avoided Project Cost Benefit = $125M

- Total Estimated Previously-Approved CEERTS Project Cost Benefit = $75M
- Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $50M

Newly-Proposed CEERTS Project Cost Allocation:

(Percentages in example are rounded to nearest whole percentage)

– Previously-Approved CEERTS Project Enrolled Transmission Providers (A & B) = ($75M / $125) = 60%

- This 60% of the cost responsibility would be allocated to Enrolled Transmission Providers A & B:
  - ☐ Enrolled Transmission Provider A = 60% * 50% = 30%
  - ☐ Enrolled Transmission Provider B = 60% * 50% = 30%

– Enrolled Transmission Provider C = ($50M / $125M) = 40%

Exhibit DR-6

Alternative Projects Load Flow Summary Table

FPSC EXH NO. 7
ADMITTED

REDACTED

Docket No: 20250078-EI
Duke Energy Florida
Witness: Dave Rahman
Exhibit No. DR-6
Page 2 of 3

[redacted]

FPSC EXH NO. 7

ADMITTED

REDACTED

Docket No: 20250078
Witness: Dave Rahman
Exhibit No. DR-6

[redacted]

Exhibit DR-7

DeLand West to Dona Vista 230 kV Line Project

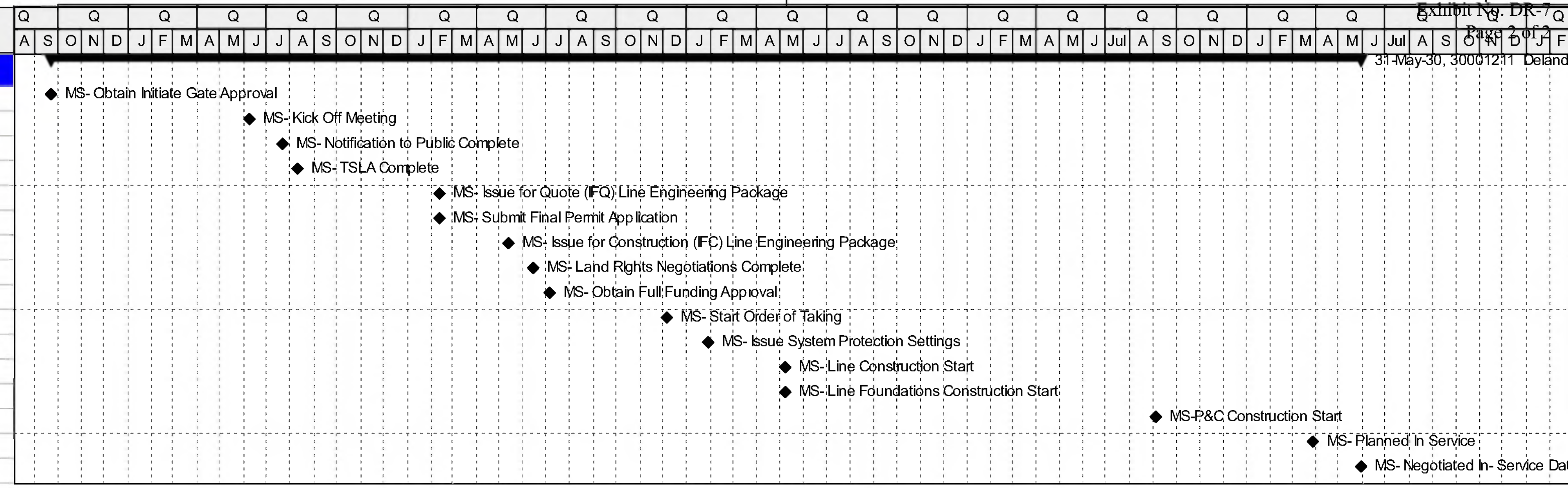
Indicative Schedule of Licensing, Design, and Construction

Docket No: 20250078-EI
Duke Energy Florida
Witness: Dave Rahmer
Exhibit No. DR-7
Page 2 of 2

FPSC EXH NO. 8
ADMITTED

Deland West-Dona Vista - New 230 kV Line | LV - Milestones | 30-Apr-25 16:39

Activity ID	Activity Name	Start	Finish
30001211	**Deland West-Dona Vista - New 230 kV Line**	22-Sep-25	31-May-30
L20400	MS- Obtain Initiate Gate Approval	22-Sep-25	
L30050	MS- Kick Off Meeting	09-Jun-26	
L30200	MS- Notification to Public Complete		21-Jul-26
L71712	MS- TSLA Complete		11-Aug-26*
L32900	MS- Issue for Quote (IFQ) Line Engineering Package		11-Feb-27
L33900	MS- Submit Final Permit Application		11-Feb-27
L40500	MS- Issue for Construction (IFC) Line Engineering Package		12-May-27
L41605	MS- Land Rights Negotiations Complete		14-Jun-27*
L40600	MS- Obtain Full Funding Approval		06-Jul-27
L71713	MS- Start Order of Taking	06-Dec-27*	
L51300	MS- Issue System Protection Settings		28-Jan-28*
L51100	MS- Line Construction Start	08-May-28*	
L51110	MS- Line Foundations Construction Start	08-May-28*	
L52000	MS-P&C Construction Start	04-Sep-29*	
L60000	MS- Planned In Service		01-Jan-30
L60100	MS- Negotiated In- Service Date		01-Jan-30



Project Baseline Bar | Remaining Work | Milestone
Actual Work | Critical Remaining Work | Summary

Page 1 of 1
Dara Date: 01-Apr-25

TASK filter: Milestone.

Exhibit DR-8

Project Decision Matrix

FPSC EXH NO. 9

ADMITTED

Exhibit No. (DR-8) - Project Decision Matrix

DECISION STATEMENT		DEF reviewed projects to: (a) improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek and Piedmont substations; (b) increase east to west power transfer capabilities of the transmission network by providing a new 230 kV circuit between the Volusia and Lake County areas of DEF's territory south of Deland; (c) relieve potential overloads and low voltage conditions under contingency events; and (d) reduce line loading on existing transmission circuits.														
		ALTERNATIVES: All in-service dates based on the Regional Load Forecast														
		In-Service Year		**Selected Project**	**In-Service Year**		**Alternative 1**	**In-Service Year**		**Alternative 2**	**In-Service Year**		**Alternative 3**	**In-Service Year**		**Alternative 4**
OBJECTIVES		2030		The Deland West to Dona Vista 230kV Project consists of a new 230kV transmission line extending from DEF's Dona Vista substation in Lake County to DEF's Deland West substation in Volusia County.	Beyond 2030		The Seneca Lakes to Deland West Project consists of a new 230 kV transmission line extending from DEF's Seneca Lakes substation in Lake County to DEF's Deland West substation in Volusia County. Additionally, two 69kV circuits will be built both from DEF's Seneca Lakes Substation to DEF's Eustis South and Sorrento substations, all located in Lake County.	Beyond 2030		The Sorrento to Deland West Project consists of a new 230 kV transmission line extending from DEF's Sorrento substation in Lake County to DEF Deland West substation in Volusia County. Additionally, two 69kV circuits will be built both from DEF's Seneca Lakes Substation to DEF's Eustis South and Sorrento substations, all located in Lake County.	Beyond 2030		The Deland West to Dona Vista 170kV Project consists of a new 170 kV transmission line extending from DEF's Dona Vista substation in Lake County to DEF's Deland West substation in Volusia County	Beyond 2030		The Deland West -Silver Springs to Dona Vista Project consists of two new 230 kV transmission lines extending from DEF's Dona Vista substation in Lake County to tap into the existing DEF's Deland West substation to Silver Springs in Marion County. This creates two new circuits separately connecting Dona Vista with Deland West and Silver Springs substations.
REQUIREMENTS		**Yes**	**No**	**Information**	**Yes**	**No**	**Information**	**Yes**	**No**	**Information**	**Yes**	**No**	**Information**	**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers		X		Meets all electrical needs.		X	This Alternative does not connect the power source to the load as well as the Project.		X	This Alternative does not connect the power source to the load as well as the Project.		X	One single point of failure due to 230/170kV which will potentially create an extended outage of the line.	X		Meets all electrical needs.
Alternative plan is feasible to construct		X		Existing corridor and majority of easements already acquired.	X		New easements required	X		New easements required	X		Existing corridor and majority of easements already acquired.	X		New easements required
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**	**Score**	**Value*Score**	**Information**	**Score**	**Value*Score**	**Information**	**Score**	**Value*Score**	**Information**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	6	51	Estimated Cost: $165M	8	68	Estimated Cost: $161M	4	34	Estimated Cost: $171M	10	85	Estimated Cost: $159M	2	17	Estimated Cost: $179M
Reliability of service to customers	10	10	100	Meets all electrical needs.	8	80	This Alternative does not connect the power source to the load as well as the Project.	8	80	This Alternative does not connect the power source to the load as well as the Project.	4	40	One single point of failure due to 230/170kV which will potentially create an extended outage of the line.	10	100	Meets all electrical needs.
Considers long-term flexibility and usefulness	7	10	70	Also rebuilds the 69kV circuits on the existing coridoor.	8	56	The additional 69kV lines being constructed improves the 69kV network.	8	56	The additional 69kV lines being constructed improves the 69kV network.	2	14	170kV is non-standard, not capable of relieving loading into North Orlando from Volusia county. Flows on 170kV aren't as high.	6	42	This Alternative will not rebuild the 69kV along the Deland West to Dona Vista, which provides less value to the long-term flexibility of this area.
Minimizes construction difficulties (Includes easements, permits)	9	10	90	Existing corridor and majority of easements already acquired.	4	36	New easements required	4	36	New easements required	8	72	Existing corridor and majority of easements already acquired.	6	54	New easements required
Environmental considerations	8	10	80	Existing corridor, environmental impacts minimized.	6	48	This alternative would require complete greenfield construction through an environmentally sensitive forest. (State lands)	6	48	This alternative would require complete greenfield construction through an environmentally sensitive forest. (State lands)	10	80	Existing corridor, environmental impacts minimized.	4	32	This alternative would require complete greenfield construction through an environmentally sensitive forest. National forest (NEPA)
Impact to customers	9.5	10	95	Existing corridor, impacts limited to customers already in corridor.	4	38	New corridor, new easement impacts to land owners	4	38	New corridor, new easement impacts to land owners	10	95	Existing corridor, minimal impact to customers	4	38	New corridor, new easement impacts to land owners
TOTAL VALUE SCORE			486			326			292			386			283	

APPENDIX A TO THE PETITION IS CONFIDENTIAL IN ITS ENTIRETY AND SUBJECT TO A REQUEST FOR CONFIDENTIAL CLASSIFICATION, FILED CONTEMPORANEOUSLY WITH THIS PETITION PURSUANT TO RULE 25-22.006, F.A.C.

Dianne M. Triplett
DEPUTY GENERAL COUNSEL

July 3, 2025

VIA ELECTRONIC FILING

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Duke Energy Florida, LLC's Petition for Determination of Need for DeLand West – Dona Vista Transmission Line;* Docket No. 20250078-EI

Dear Mr. Teitzman:

Enclosed for filing is Duke Energy Florida, LLC's (DEF) Notice of Filing Notices of Final Hearing in Areas Where Proposed Line Could be Placed and Affidavits of Publication

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Sincerely,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/clg
Enclosures

299 First Avenue North ▪ St. Petersburg, Florida 33701
Phone: 727.820.4692 ▪ Email: dianne.triplett@duke-energy.com

FPSC EXH NO. 11

ADMITTED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for DeLand West-Dona Vista Transmission Line in Volusia and Lake Counties, by Duke Energy Florida, LLC.	DOCKET NO. 20250078-EI DATED: July 3, 2025

DUKE ENERGY FLORIDA, LLCS NOTICE OF FILING NOTICES OF FINAL HEARING PUBLISHED IN NEWSPAPERS IN AREAS WHERE PROPOSED LINE COULD BE PLACED AND AFFIDAVITS OF PUBLICATION

Pursuant to Rule 25-22.075(4), Florida Administrative Code, Duke Energy Florida, LLC ("DEF"), by and through its undersigned counsel, hereby submits the Notices of Final Hearing published in the following newspapers of general circulation on one-quarter page where DEF's proposed DeLand West – Dona Vista 230kV transmission line could be placed:

1. Volusia Beacon
2. Volusia Review (part of the Daytona Beach News Journal)
3. Hometown News Volusia (digital)*
4. Leesburg Daily Commercial*
5. Orlando Sentinel Volusia Extra Lake Sentinel
6. North Lake Outpost

The above referenced Notices of Final Hearing and the Affidavits of Publication of such Notices are filed herewith as composite Exhibit "A" to this Notice of Filing.

Respectfully submitted this 3rd day of July, 2025.

/s/ Dianne M. Triplett
DIANNE M. TRIPLETT

*These are sister online newspapers and notice appeared in both, along with several other editions of the Hometown family of newspapers.

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FLRegulatory@Duke-Energy.com

Attorneys for Duke Energy Florida, LLC

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Electronic Mail to the following on the 3rd day of July, 2025:

/s/ Dianne M. Triplett
Attorney

Adria Harper / Jennifer Augspurger Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 aharper@psc.state.fl.us jaugspur@psc.state.fl.us	

EXHIBIT A

NOTICES OF FILING HEARING AND AFFIDAVITS OF PUBLICATION

FPSC EXH NO. 11

ADMITTED

Volusia Beacon Affidavit and Tear Sheet – Published June 5, 2025

The Beacon
PUBLISHED WEEKLY
State of Florida
COUNTY OF VOLUSIA SS

Before the undersigned authority personally appeared _____Barb Shepherd___, who on oath says that he/she is the Classified Advertising Representative of The Beacon, a weekly newspaper published at __DeLand________, in ______Volusia____________ County, Florida; that the attached copy of advertisement, being a____NOTICE OF HEARING_______________ ______________DUKE ENERGY__________________ In the matter of____________________________________ Dona Vista Transmission Line in Volusia and Lake Counties in the ____________Court, was published in said newspaper, in the issue(s) of _____________________ ________________June 5, 2025___________________ newspaper published at DeLand, in said Volusia County, Florida, and that the said newspaper has heretofore been continuously published in said Volusia County, Florida, each week and has been entered as second-class mail matter at the post office in DeLand in said Volusia County, Florida, for a period of one year preceding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Barb Shepherd

The foregoing instrument was acknowledged before me this __5th_day of__June, 2025__, by ___Barb Shepherd___, who is personally known to me and who did take an oath.

Melodie W. Robinson

(SEAL) MELODIE W. ROBINSON
Commission # HH 306225
Expires October 19, 2026

NOTICE OF HEARING

The FLORIDA PUBLIC SERVICE COMMISSION announces a hearing in the following docket to which all persons are invited.

DOCKET NO. AND TITLE: Docket Number 20250078-EI – Petition for determination of need for DeLand West – Dona Vista transmission line in Volusia and Lake Counties, by Duke Energy Florida, LLC

HEARING

DATE AND TIME: July 22-23, 2025, at 9:30 a.m.

PLACE: Room 148, Betty Easley Conference Center, 4075 Esplanade Way, Tallahassee, Florida.

GENERAL SUBJECT MATTER TO BE CONSIDERED: The purpose of this hearing is for the Commission to take final action to determine the need, pursuant to Section 403.537, Florida Statutes (F.S.), for Duke Energy Florida, LLC (DEF) proposed construction of a 230 kV electrical transmission line that would be located in parts of Volusia and Lake counties. The proposed electrical transmission line will start at DEF's existing DeLand West Substation in Volusia County and will terminate at DEF's existing Dona Vista Substation in Lake County. The Commission may rule on any such matters from the bench or may take the matters under advisement. This proceeding shall: (1) allow DEF to present evidence and testimony in support of its petition for a determination of need for the DeLand West-Dona Vista 230 kV transmission line; (2) permit any intervenors to present testimony and exhibits concerning this matter; (3) permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and (4) allow for such other purposes as the Commission may deem appropriate.

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VOLUSIA REVIEW
Published Weekly
Daytona Beach, Volusia County, Florida
PO Box 631244 Cincinnati, OH 45263-1244

AFFIDAVIT OF PUBLICATION

Gail Simpson
Mary Carpenter
Duke Energy
4800 Paradise WAY S
St Petersburg FL 33705-4709

STATE OF WISCONSIN, COUNTY OF BROWN

Before the undersigned authority personally appeared, who on oath says that he or she is the Legal Coordinator of the Volusia Review, published in Volusia County, Florida; that the attached copy of advertisement, being a Classified Legal CLEGL, was published on the publicly accessible website of Volusia County, Florida, or in a newspaper by print in the issues of, on:

06/09/2025

Affiant further says that the website or newspaper complies with all legal requirements for publication in chapter 50, Florida Statutes.
Subscribed and sworn to before me, by the legal clerk, who is personally known to me, on 06/09/2025

Legal Clerk

Notary, State of WI, County of Brown

3.7.27

My commission expires

Publication Cost:	$270.65		
Tax Amount:	$0.00		
Payment Cost:	$270.65		
Order No:	11378830	# of Copies:	
Customer No:	1536402	1	
PO #:	20250078-EI		

THIS IS NOT AN INVOICE!

Please do not use this form for payment remittance.

KAITLYN FELTY
Notary Public
State of Wisconsin

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DB-41968900

FPSC EXH NO. 11

ADMITTED

Hometown News

Hometown News Media Group
P.O. Box 850
Ft Pierce FL 34954

Proof of Publication
Hometown News Media Group
Published Weekly

In the State of Florida counties: Martin, St. Lucie, Indian River, Brevard, and Volusia. Affiant further states that the website or newspaper complies with all legal requirements for publication in Chapter 50, Florida Statutes.

This will certify that the attached ad ran in the Hometown News Media Group issues of:

New Smyrna Beach 06/06/2025
Port Orange 06/06/2025
Ormond Beach 06/06/2025
Deland 06/06/2025
Deltona 06/06/2025

Hometown News Media Group Representative:

HD HEATHER DONALDSON

I have hereunto set my hand and affixed my official stamp, the day and year aforesaid.

Amanda Wheaton

Notary Public
My commission expires: 8/5/26

AMANDA WHEATON
NOTARY PUBLIC
MY COMMISSION EXPIRES 8-5-2026
STATE OF FLORIDA
COMMISSION NUMBER HH 254541

LEGAL NOTICES

5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5040 Notice of Meeting/Hearing | 5040 Notice of Meeting/Hearing | 5040 Notice of Meeting/Hearing | 5040 Notice of Meeting/Hearing

NOTICE OF AGENCY ACTION TAKEN BY THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

Notice is given that the following permit was issued on May 23, 2025: City of Edgewater, 104 N. Riverside Drive, Edgewater, FL 21332 permit #22969-7. The project is located in Volusia County, Section 3, Township 18S South, Range 34E East. The permit authorizes a surface water management system on 9.3 acres for an Emergency Outfall known as Duck Pond Emergency Outfall. The receiving water body is the Indian River Lagoon.

A person whose substantial interests are or may be affected has the right to request an administrative hearing by filing a written petition with the St. Johns River Water Management District (District). Pursuant to Chapter 28-106 and Rule 40C-1.1007, Florida Administrative Code (F.A.C.), the petition must be filed (received) either by delivery at the office of the District Clerk at District Headquarters, P.O. Box 1429, Palatka FL 32178-1429 (4049 Reid St, Palatka, FL 32177) or by e-mail with the District Clerk at Clerk@sjrwmd.com, within twenty-one (21) days of newspaper publication of the notice of District decision (for those persons to whom the District does not mail or email actual notice). A petition must comply with Sections 120.54(5)(b)4. and 120.569(2)(c), Florida Statutes (F.S.), and Chapter 28-106, F.A.C. The District will not accept a petition sent by facsimile (fax). Mediation pursuant to Section 120.573, F.S., may be available and choosing mediation does not affect your right to an administrative hearing.

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HEARING

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FPSC EXH NO. 11

ADMITTED

C2-115

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5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action

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5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action | 5010 Notice of Action

NOTICE OF AGENCY ACTION TAKEN BY THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

Notice is given that the following permit was issued on May 23, 2025: City of Edgewater, 104 N. Riverside Drive, Edgewater, FL 21332 permit #22969-7. The project is located in Volusia County, Section 3, Township 18S South, Range 34E East. The permit authorizes a surface water management system on 9.3 acres for an Emergency Outfall known as Duck Pond Emergency Outfall. The receiving water body is the Indian River Lagoon.

A person whose substantial interests are or may be affected has the right to request an administrative hearing by filing a written petition with the St. Johns River Water Management District (District). Pursuant to Chapter 28-106 and Rule 40C-1.1007, Florida Administrative Code (F.A.C.), the petition must be filed (received) either by delivery at the office of the District Clerk at District Headquarters, P.O. Box 1429, Palatka FL 32178-1429 (4049 Reid St, Palatka, FL 32177) or by e-mail with the District Clerk at Clerk@sjrwmd.com, within twenty-one (21) days of newspaper publication of the notice of District decision (for those persons to whom the District does not mail or email actual notice). A petition must comply with Sections 120.54(5)(b)4. and 120.569(2)(c), Florida Statutes (F.S.), and Chapter 28-106, F.A.C. The District will not accept a petition sent by facsimile (fax). Mediation pursuant to Section 120.573, F.S., may be available and choosing mediation does not affect your right to an administrative hearing.

A petition for an administrative hearing is deemed filed upon receipt of the complete petition by the District Clerk at the District Headquarters in Palatka, Florida during the District's regular business hours. The District's regular business hours are 8 a.m. – 5 p.m., excluding weekends and District holidays. Petitions received by the District Clerk after the District's regular business hours shall be deemed filed as of 8 a.m. on the District's next regular business day. The District's acceptance of petitions filed by e-mail is subject to certain conditions set forth in the District's Statement of Agency Organization and Operation (issued pursuant to Rule 28-101.001, Florida Administrative Code), which is available for viewing at www.sjrwmd.com. These conditions include, but are not limited to, the petition being in the form of a PDF or TIFF file and being capable of being stored and printed by the District. Further, pursuant to the District's Statement of Agency Organization and Operation, attempting to file a petition by facsimile (fax) is prohibited and shall not constitute filing.

The right to an administrative hearing and the relevant procedures to be followed are governed by Chapter 120, Florida Statutes, Chapter 28-106, Florida Administrative Code, and Rule 40C-1.1007, Florida Administrative Code. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means the District's final action may be different from the position taken by it in this notice. **Failure to file a petition for an administrative hearing within the requisite time frame shall constitute a waiver of the right to an administrative hearing. (Rule 28-106.111, F.A.C.).**

If you wish to do so, please visit http://www.sjrwmd.com/nor_dec/ to read the complete Notice of Rights to determine any legal rights you may have concerning the District's decision(s) on the permit application(s) described above. You can also request the Notice of Rights by contacting the Director of Records and Regulatory Support, 4049 Reid St., Palatka, FL 32177-2529, tele. no. (386)329-4570.

NOTICE OF HEARING

The FLORIDA PUBLIC SERVICE COMMISSION announces a hearing in the following docket to which all persons are invited.

DOCKET NO. AND TITLE: Docket Number 20250078-EI – Petition for determination of need for DeLand West – Dona Vista transmission line in Volusia and Lake Counties, by Duke Energy Florida, LLC

HEARING

DATE AND TIME: July 22-23, 2025, at 9:30 a.m.
PLACE: Room 148, Betty Easley Conference Center, 4075 Esplanade Way, Tallahassee, Florida.

GENERAL SUBJECT MATTER TO BE CONSIDERED: The purpose of this hearing is for the Commission to take final action to determine the need, pursuant to Section 403.537, Florida Statutes (F.S.), for Duke Energy Florida, LLC (DEF) proposed construction of a 230 kV electrical transmission line that would be located in parts of Volusia and Lake counties. The proposed electrical transmission line will start at DEF's existing DeLand West Substation in Volusia County and will terminate at DEF's existing Dona Vista Substation in Lake County. The Commission may rule on any such matters from the bench or may take the matters under advisement. This proceeding shall: (1) allow DEF to present evidence and testimony in support of its petition for a determination of need for the DeLand West-Dona Vista 230 kV transmission line; (2) permit any intervenors to present testimony and exhibits concerning this matter; (3) permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and (4) allow for such other purposes as the Commission may deem appropriate.

Members of the public who are not parties to the need determination proceeding shall have an opportunity to present sworn testimony at the hearing regarding the need for the proposed DeLand West-Dona Vista 230 kV transmission line. By providing public testimony, a person does not become a party to the proceeding.

To become an official party of record, you must file a Petition for Intervention at least five days before the final hearing, pursuant to the requirements contained in Rule 28-106.205, Florida Administrative Code (F.A.C.). All witnesses shall be subject to cross examination at the conclusion of their testimony.

The hearing will be governed by the provisions of Chapter 120, F.S.; Section 403.537, F.S.; and Chapters 25-22 and 28-106, F.A.C. Only issues relating to the need for the DeLand West-Dona Vista 230 kV transmission line will be heard at the July 22, 2025, hearing.

Separate public hearings will be held before the Division of Administrative Hearings to consider environmental and other impacts of the proposed construction of the DeLand West-Dona Vista 230 kV transmission line, as required by the "Transmission Line Siting Act," Sections 403.52- 403.5365, F.S.

Any person requiring some accommodation at this proceeding because of a physical impairment is asked to advise the agency no later than five days prior to the hearing by contacting: Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850 or at (850) 413-6770. If you are hearing or speech impaired, please contact the Agency using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD) or 1-800-955-8770 (Voice). For more information, you may contact: Florida Public Service Commission, Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Emergency Cancellation of Hearing - If a named storm or other disaster requires cancellation of the proceedings, Commission staff will attempt to give timely direct notice to the Parties. Notice of cancellation of the proceedings will also be provided on the Commission's website (http://www.psc.state.fl.us/) under the Hot Topics link found on the home page. Cancellation can also be confirmed by calling the Office of the General Counsel at (850) 413-6199.

For more information, you may contact: Florida Public Service Commission, Office of the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, (850) 413-6770.

Orlando Sentinel
MEDIA GROUP

Published Daily in
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400 S Tryon Ste 1800
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State Of Florida
County Of Orange

Before the undersigned authority personally appeared Rose Williams, who on oath says that he or she is a duly authorized representative of the ORLANDO SENTINEL, a DAILY newspaper published in ORANGE County, Florida; that the attached copy of advertisement, being a Legal Notice in:

The matter of 11200-Misc. Legal
Was published in said newspaper by print in the issues of, or by publication on the newspaper's website, if authorized on Jun 06, 2025.

Affiant further says that the newspaper complies with all legal requirements for publication in Chapter 50, Florida Statutes.

Rose Williams

Rose Williams	**Rose Williams**
Signature of Affiant	Name of Affiant

Sworn to and subscribed before me on this 6 day of June, 2025,
by above Affiant, who is personally known to me (X) or who has produced identification ( ).

LeAnne Rollins
Signature of Notary Public

Notary Public State of Florida
Leanne Rollins
My Commission HH 500022
Expires 4/27/2028

Name of Notary, Typed, Printed, or Stamped

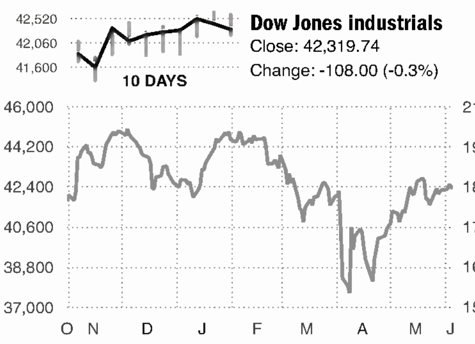
7823216

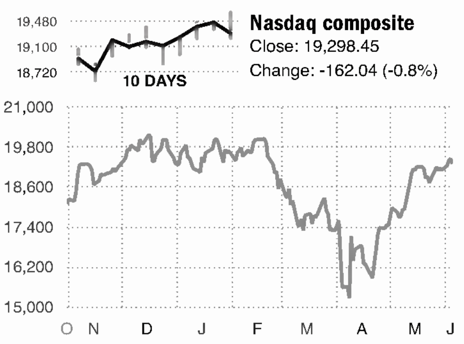
Orlando Sentinel

WALL STREET REPORT

MONEY & MARKETS

DOW 42,319.74 -108.00 -0.26%
NASDAQ 19,298.45 -162.04 -0.83%
S&P 500 5,939.30 -31.51 -0.53%
EURO 1.145 0.00358 0.31%
CRUDE OIL 62.85 -0.56 -0.88%
GOLD 3,373.50 23.30 0.70%
6-MO T-BILLS 4.28 0.0 0.0%
30-YR T-BONDS 4.88 0.0 0.04%





StocksRecap

	NYSE	NASD
Vol. (in mil.)	4830	4212
Pvs. Volume	4719	4593
Advanced	1316	1408
Declined	1294	1978
New Highs	32	70
New Lows	9	34

	HIGH	LOW	CLOSE	CHG	%CHG	WK	MO	QTR	YTD
DOW	42,601.45	42,211.69	42,319.74	-108.00	-0.26%	▲	▲	▲	-0.53%
DOW Trans.	14,755.91	14,599.42	14,639.63	-53.98	-0.37%	▼	▼	▼	-7.90%
DOW Util.	1,035.28	1,029.57	1,031.88	-0.60	-0.06%	▼	▼	▲	+5.00%
NYSE Comp.	19,959.07	19,831.31	19,883.29	-4.04	-0.02%	▲	▲	▲	+4.12%
NASDAQ	19,610.51	19,226.22	19,298.45	-162.04	-0.83%	▲	▲	▲	-0.06%
S&P 500	5,999.70	5,921.20	5,939.30	-31.51	-0.53%	▲	▲	▲	+0.98%
S&P 400	3,040.03	3,007.82	3,021.27	-3.79	-0.12%	▲	▲	▲	-3.19%
Wilshire 5000	59,943.37	59,171.19	59,353.84	-277.97	-0.47%	▲	▲	▲	+0.65%
Russell 2000	2,110.08	2,086.79	2,097.35	-1.13	-0.05%	▲	▲	▲	-5.95%

Commodities

Unleaded gas fell 1.92% to $2.034, while heating oil dropped 1.43% to $2.0701. Platinum rose 1.62% to $1088.7, and coffee increased 1.47% to $3.46.

FUELS	CLOSE	PVS.	CHG	%YTD
Crude Oil (bbl)	62.85	63.41	-0.56	-11.8
Heating Oil (gal)	2.07	2.10	-0.03	-9.7
Natural Gas (mm btu)	3.72	3.72	-0.01	+0.6
Unleaded Gas (gal)	2.03	2.08	-0.04	+2.5

METALS	CLOSE	PVS.	CHG	%YTD
Aluminum (ton)	2,411.25	2,386.50	+24.75	-4.1
Copper (lb)	4.86	4.81	+0.05	+22.8
Gold (oz)	3,373.50	3,350.20	+23.30	+27.5
Platinum (oz)	1,088.70	1,071.30	+17.40	+25.6
Silver (oz)	34.52	34.50	+0.02	+23.2

AGRICULTURE	CLOSE	PVS.	CHG	%YTD
Cattle (lb)	2.18	2.16	+0.02	+16.4
Coffee (lb)	3.46	3.41	+0.05	+12.0
Corn (bu)	4.39	4.39	+0.00	-4.1
Cotton (lb)	64.99	66.05	-1.06	-4.5
Lumber (1,000 bd ft)	606.00	592.50	+13.50	-1.5
Orange Juice (lb)	2.77	2.83	-0.06	-44.3
Soybeans (bu)	10.52	10.45	+0.07	+5.4
Wheat (bu)	5.46	5.43	+0.03	-1.1

Foreign Exchange

Japanese Yen rose 0.494%, leading gains. South African Rand fell most at -0.717%. Euro increased 0.314%, while Chinese Yuan decreased by -0.398%.

MAJORS	CLOSE	CHG	%CHG	6MO AGO	1YR AGO
British Pound (GBP/USD)	1.3565	+.0020	+.15%	1.2758	1.2785
Canadian Dollar	1.3674	+.0003	+.02%	1.4022	1.3693
Euro (EUR/USD)	1.1447	+.0036	+.31%	1.0586	1.0870
Japanese Yen	143.478	+.7050	+.49%	150.09	156.05
Mexican Peso	19.1450	-.0383	-.20%	20.180	17.487
EUROPE/AFRICA/MIDDLE EAST					
Israeli Shekel	3.4909	+.0073	+.21%	3.5980	3.7140
Norwegian Krone	10.0697	-.0401	-.40%	11.014	10.557
South African Rand	17.6858	-.1278	-.72%	18.000	18.902
Swedish Krona	9.5508	-.0146	-.15%	10.847	10.383
Swiss Franc	.8201	+.0027	+.33%	.8784	.8934
ASIA/PACIFIC					
Australian Dollar	1.5345	-.0059	-.38%	1.5494	1.5038
Chinese Yuan	7.1750	-.0287	-.40%	7.2592	7.2467
Hong Kong Dollar	7.8460	+.0011	+.01%	7.7828	7.8117
Indian Rupee	85.8638	-.0073	-.01%	84.666	83.408
Singapore Dollar	1.2845	-.0016	-.12%	1.3380	1.3481
South Korean Won	1354.53	-6.540	-.48%	1410.9	1366.7
Taiwan Dollar	29.9419	+.0003	+.00%	32.340	32.251

Interest rates

The yield on the 10-year Treasury note rose to 4.395%. Yields affect interest rates on mortgages and other consumer loans.

TREASURIES	LAST	PVS	NET CHG	WK	MO	QTR	1YR AGO
3-month T-bill	4.36	4.36	0.00	–	▲	▲	4.42
6-month T-bill	4.28	4.28	0.00	▼	▲	▲	4.35
1-year T-note	4.08	4.06	+0.02	▼	▲	▲	4.19
2-year T-note	3.93	3.87	+0.06	▼	▲	▼	4.10
5-year T-note	3.99	3.93	+0.06	▼	▲	▼	4.03
10-year T-note	4.39	4.36	+0.04	▼	▲	▲	4.15
30-year T-note	4.88	4.88	0.00	▼	▲	▲	4.33

CONSUMER RATES	NAT'L AVG		WK AGO	6MO AGO	1YR AGO
48 month new car loan	7.20	–	7.20	7.41	7.90
Money Market Account	0.44	▼	0.44	1.46	1.68
1 year cd	1.98	▼	1.99	3.41	3.81
$30K Home equity loan	8.65	▲	8.47	8.17	9.04
30 year fixed mortgage	6.94	▼	7.00	6.96	7.23
15 year fixed mortgage	6.18	▼	6.22	6.40	6.80

LOCAL STOCKS

NAME	CLOSE	%CHG
ADP	326.23	-0.0%
AMD	115.69	-2.4%
ASML Holding N.V.	747.76	+0.7%
AT & T Inc.	27.76	+1.5%
AbbVie Inc.	187.47	+0.1%
Accenture PLC	315.38	-0.3%
Alphabet A	168.21	+0.1%
Alphabet C	169.81	+0.2%
Amazon	207.91	+0.3%
American Express Co.	295.96	+0.0%
Apple	200.63	-1.1%
Bank of America Corp	44.38	+0.0%
Best Buy Co. Inc.	70.46	+1.1%
Bk of New York Mellor	88.58	+0.3%
Boeing Co.	209.02	-1.4%
Brinker International I	169.33	-2.4%
Broadcom	259.93	-0.4%
Brown & Brown Inc.	110.03	-1.0%
Brunswick Corp.	55.00	+0.5%
CVS Health Corp.	63.08	-0.8%
Cemex S.A.B. de C.V.	6.81	+0.4%
Charles Schwab Corp.	87.24	-0.3%
Cisco Systems Inc.	64.62	+0.4%
Citigroup Inc.	76.67	+0.4%
Coca-Cola	70.91	-0.6%
Comcast Corp.	34.22	-0.6%
Cracker Barrel	53.63	-7.1%
D.R. Horton Inc.	122.74	-0.6%
Darden Restaurants Ir	215.06	-0.6%
Delta Air Lines Inc.	48.84	-0.3%
Dillards Inc.	394.68	-1.2%
Disney	112.53	-0.8%
Duke Energy Corp.	115.74	-0.2%
Electronic Arts Inc.	147.88	-0.4%
Emcor Group Inc.	484.06	+0.3%
Encompass Health Co	121.29	+0.0%
Energy Transfer L.P.	17.67	+0.8%
Exxon Mobil Corp.	101.83	-0.5%
Faro Technologies Inc	42.42	-0.2%
Fedex Corp.	216.73	-1.0%
Fifth Third Bancorp	38.30	-0.4%
Fiserv Inc.	165.38	+0.7%
Ford Motor Co.	10.10	-1.4%
Gen Digital Inc.	29.13	+0.1%
Gencor Industries Inc.	14.14	-0.8%
Grab Holdings Limitec	5.06	+0.8%
Hilton Grand Vacation	39.03	+0.7%
Home Depot	369.28	-0.8%
Hyatt Hotels Corp.	129.96	-0.8%
Insperity Inc.	63.62	-0.3%
Intel Corp.	19.99	-1.3%
Intl Business Machine	266.86	+0.5%
JPMorgan Chase & Cc	261.95	-0.9%
JetBlue Airways	4.88	-3.0%
Kohl's Corp.	8.57	+5.4%
L3Harris Technologies	242.06	-0.1%
LGL Group Inc.	6.61	+0.2%
Lennar Corp.	110.06	-0.2%
LightPath Technologie	2.94	+1.4%
Lockheed Martin Corp	478.03	-0.9%
Loews Corp.	88.61	+0.5%
Lowe's Companies Inc	227.59	-0.3%
Lucid Grp	2.13	-4.5%
Lumen Technologies I	3.96	+1.3%
Macy's, Inc.	11.92	+4.1%
Marriott Vacat.Worldw	65.02	-0.8%
McDonald's Corp.	308.98	-0.8%
Microsoft Corp.	467.68	+0.8%
NNN REIT Inc.	41.30	-0.2%
NVIDIA Corp.	139.99	-1.4%
NatWest Group PLC	14.27	-0.9%
Nextera Energy Inc.	71.50	+2.3%
Northrop Grumman Cc	488.12	-0.6%
Nu Holdings Ltd.	12.11	+1.4%
PepsiCo Inc.	131.11	-0.5%
Pfizer Inc.	23.12	-1.2%
RTX Corp.	139.07	+0.4%
Restaurant Brands Int	71.39	-0.2%
Simon Property Grour	160.75	-0.5%
Sony Group Corp.	26.33	-1.3%
Southwest Airlines Co	32.46	+0.6%
Stellantis N.V.	9.68	-2.3%
Sysco Corp.	73.77	+1.2%
Takeda Pharmaceutica	14.99	-0.3%
Target Corp.	93.52	-0.4%
Tesla Inc.	284.70	-14.3%
Travel + Leisure Co.	48.62	-0.6%
Truist Financial Corp.	39.63	+0.3%
UBS Group AG	32.85	+0.0%
United Airlines Holdin	80.35	-1.6%
United Parcel Service	96.87	-1.7%
United Parks & Resort	43.08	-0.7%
Verizon Communicatio	43.30	+0.1%
Walgreens Boots Allia	11.25	+0.2%
Walmart Inc.	97.96	-1.4%
Waste Management In	238.64	-0.1%
Wells Fargo & Co.	74.90	-0.6%
Xenia Hotels & Resort	11.97	+0.3%
Yum! Brands, Inc.	142.88	-0.8%

The Clinton Clean Energy Center will expand output at its facility in Clinton, Illinois. The plant currently powers the equivalent of 800,000 homes. JOHN DIXON/THE NEWS-GAZETTE 2016

Meta joins others in turning to nuclear power for AI needs

By Matt Ott
Associated Press

WASHINGTON — Meta has cut a 20-year deal to secure nuclear power to help meet surging demand for artificial intelligence and other computing needs at Facebook's parent company.

The investment with Meta will also expand the output of a Constellation Energy Illinois nuclear plant.

The agreement announced this week is just the latest in a string of tech-nuclear partnerships as the use of AI expands. Financial details of the agreement Tuesday were not disclosed.

Constellation's Clinton Clean Energy Center was actually scheduled to close in 2017 after years of financial losses but was saved by legislation in Illinois establishing a zero-emission credit program to support the plant into 2027. The agreement takes effect in June of 2027, when the state's taxpayer funded zero-emission credit program expires.

With the arrival of Meta, Clinton's clean energy output will expand by 30 megawatts, preserve 1,100 local jobs and bring in $13.5 million in annual tax revenue, according to the companies. The plant currently powers the equivalent of about 800,000 homes.

George Gross, professor of electrical and computer engineering at the University of Illinois, estimates that 30 additional megawatts would be enough to power a city of about 30,00 residents for one year.

Surging investments in small nuclear reactors come at a time when large tech companies are facing two major demands: a need to increase their energy supply for AI and data centers, among other needs, while also trying to meet their long-term goals to significantly cut greenhouse gas emissions.

Constellation, owner of the shuttered Three Mile Island nuclear power plant, said in September that it planned to restart the reactor so tech giant Microsoft could secure power to supply its data centers. Three Mile Island, located on the Susquehanna River just outside Harrisburg, Pennsylvania, was the site of the nation's worst commercial nuclear power accident in 1979.

Also last fall, Amazon said it was investing in small nuclear reactors, two days after a similar announcement by Google. Additionally, Google announced last month that it was investing in three advanced nuclear energy projects with Elementl Power.

States have been positioning themselves to meet the tech industry's power needs as policymakers consider expanding subsidies and gutting regulatory obstacles.

Last year, 25 states passed legislation to support advanced nuclear energy, and lawmakers this year have introduced over 200 bills supportive of nuclear energy, according to the trade association Nuclear Energy Institute.

Still, it's unlikely the U.S. could quadruple its nuclear production within the next 25 years. The United States lacks any next-generation reactors operating commercially and only two new large reactors have been built from scratch in nearly 50 years. Those two reactors, at a nuclear plant in Georgia, were completed years late and at least $17 billion over budget.

FPSC EXH NO. 11

ADMITTED

Affidavit of Publication
NORTH LAKE OUTPOST
Serving North Lake County Florida
Located in Umatilla, Lake County, Florida
STATE OF FLORIDA,
COUNTY OF LAKE

Before the undersigned authority personally appeared Matt A. Newby

Matt A. Newby

who on oath says that he or she is Publisher of the North Lake Outpost, a weekly newspaper published at 131 North Central Avenue, Umatilla, in Lake County, Florida; that the attached copy of advertisement, being a legal notice in the matter of

NOTICE OF PUBLIC HEARING
THE FLORIDA PUBLIC SERVICE COMMISSION ANNOUNCES A HEARING FOR DOCKET NUMBER AND TITLE: 20250078-EI - DUKE ENERGY FLORIDA, LLC

was published in said newspaper in the issue of:

6-5-25.

Affiant further says that the said publication is a newspaper Published at 131 North Central Avenue, Umatilla, in said Lake County, Florida, and that the said newspaper has heretofore been continuously published in said Lake County, Florida each week and has been entered as periodicals matter at the post office in Umatilla, in said Lake County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this 5th day of JUNE 2025.

Denise E. Reed

Notary Public

Denise E. Reed
Printed Name

DENISE E REED
Notary Public - State of Florida
Commission # HH 276322
My Comm. Expires Jun 14, 2026
Bonded through National Notary Assn.

FPSC EXH NO. 12

ADMITTED

12

DEF's Response to Staff's First Set of Interrogatories Nos. 1-5

(Including Attachments)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for DeLand West-Dona Vista Transmission Line in Volusia and Lake Counties, by Duke Energy Florida, LLC.	DOCKET NO. 20250078-EI DATED: June 23, 2025

DUKE ENERGY FLORIDA, LLC'S REDACTED RESPONSE TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-5)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") First Set of Interrogatories to DEF (Nos. 1-5), as follows:

INTERROGATORIES

1. For the proposed project and each of the Alternative projects identified by witness Rahman, please answer the following questions:

   a. Please identify the estimated annual and cumulative net system cost values over the life of the project in nominal and net present value. This should include the following categories, at a minimum: Equipment & Installation; Land, Right-of-Way; and, Operation & Maintenance (O&M) for the project. If applicable, please also include the impacts on DEF's system, including System Dispatch (reporting Fuel and Emissions separately), Avoided Generation, Avoided Transmission, and Avoided Fixed O&M. Please provide these responses in electronic (Excel) format.

   b. Please detail the assumptions, facts and figures used to determine the value for each of the categories discussed in your response to 1(a). As part of your response, if this category is not applicable, please explain why not.

   c. Please provide the cumulative present value revenue requirements (CPVRR) for the project. Provide the results in an Excel spreadsheet with formulas intact. Identify any assumptions used in your calculations.

   d. Please describe any routing, right-of-way, or land acquisition difficulties DEF expects for the project.

Response:

a. For project cost values, see attachment "DEF Response_ROG1-1a_Project Cost Values.xlsx", bearing Bates number 20250078-STAFFROG1-00000001. DEF has included 2025 actuals through May, annual cost estimates by category for 2025 through

2031, and the "Total Project (cost) Estimate". Note, DEF's Total Project Estimate provided herein is a Duke Energy PMCoE Class 5 Estimate.

As a part of this project, the DEF system will not be impacted with changes to System Dispatch. DEF will still be serving with the existing generation plan. Furthermore, this is strictly a reliability project for DEF, and therefore DEF does not have any avoided Generation or Transmission costs, nor any other avoided Fixed O&M costs.

b. For assumptions, please see column "**Detail/Assumptions**" in attachment "DEF Response_ROG1-1a_Project Cost Values.xlsx", bearing Bates number 20250078-STAFFROG1-00000001, provided in DEF's response to Staff ROG 1-1(a) above.

c. DEF has not prepared a CPVRR analysis. CPVRR analyses are applicable to define the difference between two alternatives that result in changes to the system dispatch and generation. In this case, since there was not a viable generation alternative considered, the comparison of alternatives is concerned with the cost of the alternative transmission selections and their impact on the area reliability. Furthermore, please see additional details in DEF's response to Staff ROG 1-2 below.

d. DEF anticipates following our existing transmission lines and therefore does not anticipate any non-typical challenges associated with routing, right-of-way, or land acquisition of the new 230 kV transmission line.

2. Refer to witness Rahman's testimony, page 20, lines 12 through 21. Please explain if any other non-transmission alternatives were considered, including a site other than the Lake Cogen site. If so, explain why these alternatives were not selected. If not, explain why not.

Response:

DEF performed a screening level review of generation options to displace the proposed transmission line. Generation options were not selected for several reasons. The two primary drivers were cost and schedule. Transmission provided an estimate of the needed capacity to offset the transmission line. This value was over 300MW. DEF would require a new generation site, a new gas interconnection, and some amount of transmission construction to connect the site to the transmission line. Assuming the need could be served with peaking (simple cycle CT) generation, DEF would anticipate at least six to seven years for the project development, construction and commissioning putting the generation in service date beyond the 2030 in-service date for the transmission. Costs for new CT generation are above $1,800/kw so the cost of the new generation would be more than $500 million, not including the cost of gas supply, well above the $165 million for the transmission line. This screening review indicated that the proposed transmission line was the best available option for the service.

3. Refer to witness Rahman's testimony, page 12, lines 3 through 17. Please detail the number of single and/or double contingency events that customers have experienced in DEF service

areas in Lake, Volusia, Seminole, and Orange counties. As part of your response, please include the year, number of affected customers, and capacity loss for each contingency event.

Response:
REDACTED
Please see attachment "DEF Response_ROG 1-3_Contingency Outages.pdf", bearing Bates numbers 20250078-STAFFROG1-00000002 through 20250078-STAFFROG1-00000003, [redacted]

[redacted]

[redacted]

4. Refer to witness Rahman's testimony, page 12, lines 14 through 17. Please detail the number of events that have caused the Lake County Under Voltage Load Shed scheme to activate. As part of your response, please include the year, number of affected customers, and capacity loss for each event.

Response:
REDACTED
[redacted]

5. Refer to witness Rahman's testimony, page 17, line 18 through page 18, line 6. Explain if a single circuit instead of the two included in Alternative IV would have been feasible to address DEF's transmission need. If so, explain why it was not discussed as an alternative. If not, explain why not.

a. What would be the impact on the estimated capital cost of eliminating the second 230kV line in Alternate IV?

b. Explain why rebuilding the 69kV line is not included in this alternative in lieu of the extra 230kV line. As part of your response, provide an estimate of the cost differential between rebuilding the 69kV line and building a new 230kV line in this alternative.

c. What would be the estimated in-service year if only one 230kV line was constructed?

<u>Response:</u>
Tapping into the existing Deland West to Silver Springs 230 kV line via a single circuit, rather than looping into it per Alternative IV, is not considered a feasible option for several technical and operational limitations. First, the single circuit option does not meet the transmission need because it has a reduced power transfer capability from the third 230 kV source to the area due to its higher impedance and line loading in comparison to the dual line configuration. This would lead to significantly lower voltages (<.95), and higher system losses under several multiple contingency scenarios, especially during its worst outage, the dual outage of the Central Florida to Haines Creek and Piedmont to Welch Road 230 kV lines.

Additionally, the single circuit tapping option, which is against our company standards, would create a three-terminal line that introduces complex protection issues that increase the risk of misoperation. Moreover, in a fault scenario that involves this line in this configuration, the entire line would have to be de-energized, at least momentarily to clear the fault.

Third, in lieu of the single circuit tapping option, our company standards would require the construction of a new switching station located in the Ocala National Forest, which would add a significant environmental and regulatory burden under NEPA.

As mentioned in witness Rahman's testimony, this route poses significant risks to the schedule and impacts customers due to NEPA's heavy scrutiny.

a. The estimated capital cost of eliminating the second 230kV line in Alternative IV is approximately a $20 million reduction. Much of the cost will still be allocated to the single circuit. Due to this route, NEPA approval will be required regardless of whether it is a double or single circuit, as further elaborated in witness Rahman's testimony. Although this may result in overall project cost savings, this project is less effective in addressing DEF's electrical needs (regardless of the inclusion of a switching station).

b. Rebuilding the 69kV line is not included in this alternative scenario primarily because it is considered a collateral benefit of using double circuit capable poles along the existing corridor to minimize customer and environmental impacts. Furthermore, it was not considered because the requirement to rebuild the 69kV lines extends beyond the 10-year horizon. However, if the 69kV project were to be included in this alternative, it would add approximately $73 million to the total cost of the alternative. Outlined below is a cost analysis for the single circuit option, which includes Alternative IV, Single Circuit option with Switching station and the reconstruction of the 69kV circuit between Dona Vista and Deland West:

69kV Rebuild	DWDV line	$73,369,640
Single (new) 230kV	Deland West to Silver Springs	$153,612,849
TOTAL		**$226,982,489**

c. The Alternative IV and the Alternative IV* (Single Circuit Option + Switching Station) both necessitate equivalent effort in terms of environmental assessment, NEPA approval, land acquisition, procurement of long lead-time materials, and construction access. Construction duration is approximately the same since it is about the same effort to set the total amount of poles. It is likely that it would only save a few weeks for wire strings, which are relatively minor durations compared to the overall project timeline.

FPSC EXH NO. 12

ADMITTED

E7

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 18th day of June, 2025, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared DAVE RAHMAN, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 1-5 from Staff's First Set of Interrogatories to Duke Energy Florida, LLC (NOS.1-5) in Docket No(s). 20250078-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of June, 2025.

David Rahman

Dave Rahman

CHANELLE L. GARDNER
Commission # HH 464855
Expires November 15, 2027

NOTARY PUBLIC
STATE OF FLORIDA

Chanelle L Gardner

Notary Public
State of Florida, at Large

My Commission Expires:

FPSC EXH NO. 12

ADMITTED

DEF Response_ROG1-1a_Project Cost Values_ROG 1-1b_Assumptions.xlsx

Staff's First Set of Interrogatories to Duke Energy Florida, LLC (NOS.1-5)

DEF's Response to Staff ROG 1-1(a) and Staff ROG 1-1(b)

1. For the proposed project and each of the Alternative projects identified by witness Rahman, please answer the following questions:

a. Please identify the estimated annual and cumulative net system cost values over the life of the project in nominal and net present value. This should include the following categories, at a minimum: Equipment & Installation; Land, Right-of-Way; and, Operation & Maintenance (O&M) for the project. If applicable, please also include the impacts on DEF's system, including System Dispatch (reporting Fuel and Emissions separately), Avoided Generation, Avoided Transmission, and Avoided Fixed O&M. Please provide these responses in electronic (Excel) format.

b. Please detail the assumptions, facts and figures used to determine the value for each of the categories discussed in your response to 1(a). As part of your response, if this category is not applicable, please explain why not.

Description	Actuals through May 2025	Remaining 2025	2026	2027	2028	2029	2030	2031	Total Project Estimate	Detail/Assumptions
Design & Project Management	$ 2,380,212	$ 667,587	$ 3,721,285	$ 2,319,890	$ 1,251,657	$ 835,763	$ 522,183	$ 233,600	$ 11,932,177	Efforts to support the Project included: Project Management, Engineering, siting, Public Engagement, Environmental and Permitting
Land Acquisition/Rights	$ 405,187		$ 5,288,721	$ 14,295,185	$ 10,102,976	$ 301,528	$ -	$ -	$ 30,393,597	Acquisition of New/Supplemental Easements; Survey efforts included.
O&M	$ -	$ -	$ -	$ -	$ 279,000	$ 348,750	$ 69,750	$ -	$ 697,500	Transfer of the existing 69Kv conductor to the New Pole.
Materials	$ -		$ -	$ 11,672,000	$ 43,875,500	$ 2,812,500	$ -	$ -	$ 58,360,000	New 230Kv Line in Approx 27 Miles, ~327 New Structures; 23 Miles with Double circuit Structures to rebuild existing 69Kv structures.
Construction	$ -		$ -	$ 2,032,200	$ 17,383,876	$ 18,808,370	$ 3,886,896	$ -	$ 42,111,342	A New 230 Kv Line and a 69 Kv line Rebuild. Clearing, Removal of existing 69Kv Structures, Matting, Challenging outage sequence and several Road crossings. Work at 7 Remote end Substations included.
Indirect	$ 143,429	$ 125,411	$ 1,382,613	$ 4,432,985	$ 11,035,542	$ 3,478,101	$ 671,824	$ 35,040	$ 21,304,946	
Annual Total	**$ 2,928,828**	**$ 792,998**	**$ 10,392,619**	**$ 34,752,260**	**$ 83,928,551**	**$ 26,585,011**	**$ 5,150,654**	**$ 268,640**	**$ 164,799,562**	

FPSC EXH NO. 12

ADMITTED

E9

REDACTED

DEF Response_ROG3_Contingency Outages.pdf

Staff's First Set of Interrogatories to Duke Energy Florida, LLC (NOS.1-5)

DEF's Response to Staff ROG 1-3

1. For the proposed project and each of the Alternative projects identified by witness Rahman, please answer the following questions: Refer to witness Rahman's testimony, page 12, lines 3 through 17. Please detail the number of single and/or double contingency events that customers have experienced in DEF service areas in Lake, Volusia, Seminole, and Orange counties. As part of your response, please include the year, number of affected customers, and capacity loss for each contingency event.

[redacted]

E9

REDACTED

DEF Response_ROG3_Contingency Outages.pdf

Staff's First Set of Interrogatories to Duke Energy Florida, LLC (NOS.1-5)
DEF's Response to Staff ROG 1-3

1. For the proposed project and each of the Alternative projects identified by witness Rahman, please answer the following questions: Refer to witness Rahman's testimony, page 12, lines 3 through 17. Please detail the number of single and/or double contingency events that customers have experienced in DEF service areas in Lake, Volusia, Seminole, and Orange counties. As part of your response, please include the year, number of affected customers, and capacity loss for each contingency event.

[redacted]

E10

13

DEF's Response to Staff's Second Set of Interrogatories Nos. 6-10

(Including Attachments)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for DeLand West-Dona Vista Transmission Line in Volusia and Lake Counties, by Duke Energy Florida, LLC.	DOCKET NO. 20250078-EI DATED: July 7, 2025

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFFS' SECOND SET OF INTERROGATORIES (NOS. 6-10)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") Second Set of Interrogatories to DEF (Nos. 6-10), as follows:

INTERROGATORIES

6. Refer to witness Rahman's Direct Testimony, page 6, line 17 to page 7 line 6, and Exhibit No. DR-3.

   a. Please identify the underlying assumptions and conditions that DEF relied upon when creating these forecasts. Also, include any sensitivities that address unusual weather patterns and growth variations.

   b. Please explain how the forecasted increase in load growth is anticipated to impact the rate of single contingency events in the transmission system by 2030.

   c. If the Commission does not approve this petition, what will be the impacts due to load growth?

Response:

a. DEF Regional Forecast Development:

DEF forecasts load for the DEF territory as a whole and then divides that growth for individual transmission areas. Details of DEF's overall load growth expectations and the underlying drivers can be found in DEF's 2025 TYSP on pages 2-1 through 2-4 and 2-31 through 2-42.

Local Area Forecast for Dona Vista Area:

The regional forecast is further refined through a coordinated effort between Distribution and Transmission business units. Distribution will extrapolate forecast information across feeder loads. That information is then passed to Transmission who will then apply this forecast across all buses in the DEF PSSE case submittal to the FRCC for the annual case development process which involves all FRCC members. The finalized versions of these cases are then used by Transmission Planning engineers to perform planning activities. For the Project, the Dona Vista load area forecast was determined by reviewing the local total load in PSSE cases for years 2024 – 2035 for Summer and years 2024 -2034 for Winter. The total % change was then calculated and an average was determined between Summer and Winter loads. This average was the anticipated 25% load growth over 10 years for the Dona Vista area.

DONA VISTA LOAD AREA TOTALS

Summer	24	25	26	27	28	29	30	31	32	33	34	35		
Dona Vista Area Load Totals	644.6	675.9	673.81	674.75	692.05	703.02	721.87	737.91	752.95	766.51	794.66	818.22		
% Change From Previous Yr		4.855724	-0.30922	0.139505	2.563913	1.585146	2.681289	2.222007	2.038189	1.800916	3.67249	2.96479		
													% Total Change	26.93453
Winter	24	25	26	27	28	29	30	31	32	33	34			
Dona Vista Area Load Totals	616.19	670.31	676.41	685.71	690.59	701.09	711.61	727.54	736.97	742.78	752.9			
% Change From Previous Yr		8.783005	0.910027	1.374906	0.711671	1.520439	1.500521	2.238586	1.296149	0.788363	1.362449			
													% Total Change	22.18834

b. The forecasted increase in load growth typically increases the impact that single contingency events have on the transmission system. As load in any particular area increases, so does its impact on facility loadings for normal and contingency scenario conditions. For this specific project, however, the number of contingency-impacted transmission lines does not increase through 2030.

c. If the Commission does not approve this petition, the double contingency loss of the two 230 kV line sources will result in increasingly lower voltages and higher overloads in the area post-contingency. There would be increased reliance on the Lake County UVLS scheme, which would be called upon to shed more and more load over time.

7. For the selected project and alternatives identified by DEF witness Rahman in Exhibit No. DR-8, please provide the total projected annual bill impact (at 1,000 kilowatt-hours) on the general body of customers' monthly bills. For the proposed project, please have a value with and without the 69 kV repowering.

Response:

The approximate impact of the selected project and alternatives on the general body of customers' monthly bills ranges from $.26 to $.31 as follows:

- Selected Project: $.29
- Selected Project less 69kV line: $.26
- Alternative 1: $.28
- Alternative 2: $.30
- Alternative 3: $.28
- Alternative 4: $.31

These amounts exclude assumptions on AFUDC, although this project will likely qualify for AFUDC. Further, the WACC, depreciation rates, separation factors, and energy sales used to calculate these levelized bill impacts are based on today's assumptions, which are subject to change. Based on these assumptions, every $5.7 million transmission investment results in approximately $.01 per 1,000 kWh on the general body of customers' monthly bills.

Please see attached document bearing bates numbers 20250078-STAFFROG2-00000004 through 20250078-STAFFROG2-00000014 for underlying assumptions and methodologies used in its calculation.

8. Please provide responses to the following questions for the selected project and alternatives identified by DEF witness Rahman in Exhibit No. DR-8:

a. Explain the availability of diverse supply sources.
b. Are there any congestion concerns? If so, please describe the concerns.
c. Describe any short-term and long-term considerations, like opportunities for upgrades.
d. Describe the feasibility of integrating solar generating capacity.

Response:

a. The Project and each of the alternatives are planned and designed to connect the Deland West to Dona Vista area to DEF's service territory-wide network. As such, DEF's full portfolio of supply sources will be available to provide power to the area via the two existing 230 kV transmission lines and the Project.

b. The Deland West to Dona Vista area does not have transmission congestion. The need for the Project is based upon the electrical need to reliably serve the load in the area under contingency scenarios.

c. DEF has not specifically designed the Project, or any of the alternatives, to incorporate upgrades such as additional generation or the incorporation of battery storage systems for voltage or capacity support. Because the selected Project and any of the alternatives will include the construction of a new transmission line, this will generally increase DEF's options to add additional support in the area in the future.

d. The construction of new transmission facilities may create an opportunity for additional solar generation development in the area. Since the issues driving the construction of the new transmission facilities are related to contingency conditions, the implementation of new solar generation in the area would not mitigate the need for the Project. However, new transmission facilities generally do create opportunities for additional interconnection. DEF has not studied the specific area of the Project for suitable locations for solar development.

9. Please identify and describe any demand side management (such as demand response or energy efficiency) methods considered by DEF that might delay or obviate the need for the Deland West to Dona Vista project. If DEF did not consider any demand side management methods, please explain why not.

Response:
DEF does not generally plan for the use of demand side management ("DSM") in its long-term transmission planning. This is due to the fact that curtailing of load in lieu of building transmission is an imprudent approach to reliability. Furthermore, there is not sufficient DSM in the Deland West to Dona Vista area to delay or obviate the need for the Deland West to Dona Vista project.

10. If the service area experiences a dual contingency event leading to a loss of load in the immediate or very near future timeframe, what measures is DEF implementing to mitigate this risk, and what factors preclude these measures from being a long term solution?

Response:
The immediate mitigation to the dual contingency event is the activation of the Lake County Under Voltage Load Shed ("UVLS") scheme. This scheme, if utilized, would cause an outage to an entire area, and as such is not considered an acceptable long-term approach to transmission reliability or customer service.

FPSC EXH NO. 13

ADMITTED

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 3rd day of July, 2025, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared DAVE RAHMAN, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 6, 8-10 from Staff's Second Set of Interrogatories to Duke Energy Florida, LLC (NOS. 6-10) in Docket No(s). 20250078-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of July, 2025.

Dave Rahman

Notary Public
State of Florida, at Large

CHANELLE L. GARDNER
Commission # HH 464855
Expires November 15, 2027

My Commission Expires:

FPSC EXH NO. 13

ADMITTED

E17

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 30th day of June, 2025, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MARCIA OLIVIER, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number(s) 7 from Staff's Second Set of Interrogatories to Duke Energy Florida, LLC (NOS. 6-10) in Docket No(s). 20250078-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of June, 2025.

Marcia Olivier

Marcia Olivier

Chanelle L Gardner

Notary Public
State of Florida, at Large

CHANELLE L. GARDNER
Commission # HH 464855
Expires November 15, 2027

NOTARY PUBLIC STATE OF FLORIDA

My Commission Expires:

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E17

7. For the selected project and alternatives identified by DEF witness Rahman in Exhibit No. DR-8, please provide the total projected annual bill impact (at 1,000 kilowatt-hours) on the general body of customers' monthly bills. For the proposed project, please have a value with and without the 69 kV repowering.

Approx. Retail Rate Impact $/1,000 kWh

($ millions)	**Selected**	**Selected less 69 kV**	**Alt 1**	**Alt 2**	**Alt 3**	**Alt 4**
Estimated Cost *	$165.0	$151.2	$161.0	$171.0	$159.0	$179.0
Transmission Sep Factor	70.369%	70.369%	70.369%	70.369%	70.369%	70.369%
Retail Cost	$116.1	$106.4	$113.3	$120.3	$111.9	$126.0
Pretax WACC	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%
Annual Return	$9.5	$8.7	$9.3	$9.9	$9.2	$10.3
Depreciation Rate	2.34%	2.34%	2.34%	2.34%	2.34%	2.34%
Retail Depreciation Exp	$2.7	$2.5	$2.7	$2.8	$2.6	$2.9
Total Revenue Requirement	$12.2	$11.2	$11.9	$12.7	$11.8	$13.3
Divide by TWh Sales	42.3	42.3	42.3	42.3	42.3	42.3
Approx. Levelized $/1,000 kWh	$0.29	$0.26	$0.28	$0.30	$0.28	$0.31

*Excludes AFUDC

Note: the WACC, depreciation rates, separation factors, and energy sales used to calculate these levelized bill impacts are based on today's assumptions, which are subject to change. Based on these assumptions, every $5.7 million transmission investment results in approximately $.01 per 1,000 kWh on the general body of customers' monthly bills.

DUKE ENERGY FLORIDA

SCHEDULE 2.2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
2024	3,287	1,671	1,966,630	0	29	3,199	41,132
FORECAST:							
2025	3,394	1,710	1,984,943	0	30	3,192	41,007
2026	3,547	1,702	2,083,782	0	29	3,171	41,031
2027	3,584	1,701	2,106,728	0	28	3,194	41,445
2028	3,628	1,703	2,130,550	0	27	3,194	41,692
2029	3,640	1,707	2,132,201	0	27	3,204	42,055
2030	3,683	1,713	2,149,925	0	26	3,207	42,347
2031	3,684	1,719	2,143,313	0	25	3,208	42,578
2032	3,676	1,726	2,130,019	0	25	3,184	42,559
2033	3,694	1,734	2,130,147	0	24	3,223	43,379
2034	3,695	1,743	2,120,081	0	24	3,220	43,828

2030
42,347

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DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	CURRENT DEPRECIATION RATES: PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROPOSED DEPRECIATION RATES: PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
STEAM PRODUCTION PLANT													
ANCLOTE STEAM PLANT													
ANCLOTE UNITS 1 AND 2													
311.00 STRUCTURES AND IMPROVEMENTS	47,582,599.77	27,275,304	06-2029	90-R2 *	(1)	423,485	0.89	06-2042	100-R2 *	(1)	1,218,237	2.56	794,752
312.00 BOILER PLANT EQUIPMENT	232,566,150.49	146,555,760	06-2029	55-R1 *	(2)	24,117,110	10.37	06-2042	55-R1 *	(3)	5,779,203	2.48	(18,337,907)
314.00 TURBOGENERATOR UNITS	164,605,220.27	103,153,710	06-2029	50-R1 *	(2)	12,592,299	7.65	06-2042	50-R1 *	(4)	4,347,330	2.64	(8,244,969)
315.00 ACCESSORY ELECTRIC EQUIPMENT	40,416,326.37	26,546,838	06-2029	70-R1.5 *	(1)	2,222,898	5.50	06-2042	70-R1.5 *	(2)	888,488	2.20	(1,334,410)
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	10,260,469.57	6,773,657	06-2029	45-R1 *	(1)	567,404	5.53	06-2042	45-R1 *	(1)	235,526	2.30	(331,878)
TOTAL ANCLOTE UNITS 1 AND 2	*495,430,766.47*	*310,305,270*				*39,923,196*	*8.06*				*12,468,784*	*2.52*	*(27,454,412)*
TOTAL ANCLOTE STEAM PLANT	***495,430,766.47***	***310,305,270***				***39,923,196***	***8.06***				***12,468,784***	***2.52***	***(27,454,412)***
CRYSTAL RIVER STEAM PLANT													
CRYSTAL RIVER UNITS 4 AND 5													
311.00 STRUCTURES AND IMPROVEMENTS	491,942,810.31	260,776,727	05-2034	90-R2 *	(1)	18,988,992	3.86	05-2034	100-R2 *	(1)	25,303,913	5.14	6,314,921
312.00 BOILER PLANT EQUIPMENT	1,748,756,395.50	1,024,816,847	05-2034	55-R1 *	(2)	86,913,193	4.97	05-2034	55-R1 *	(3)	85,790,303	4.91	(1,122,890)
314.00 TURBOGENERATOR UNITS	353,386,402.73	218,962,928	05-2034	50-R1 *	(2)	18,270,077	5.17	05-2034	50-R1 *	(4)	16,767,374	4.74	(1,502,703)
315.00 ACCESSORY ELECTRIC EQUIPMENT	189,292,302.54	113,118,422	05-2034	70-R1.5 *	(1)	8,480,295	4.48	05-2034	70-R1.5 *	(2)	8,719,708	4.61	239,413
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	41,549,297.74	23,442,989	05-2034	45-R1 *	(1)	2,285,211	5.50	05-2034	45-R1 *	(1)	2,067,165	4.98	(218,046)
TOTAL CRYSTAL RIVER UNITS 4 AND 5	*2,824,927,208.82*	*1,641,117,914*				*134,937,768*	*4.78*				*138,648,463*	*4.91*	*3,710,695*
CRYSTAL RIVER RAIL CARS													
312.00 BOILER PLANT EQUIPMENT	3,679,303.33	2,547,149	05-2034	55-R1 *	(2)	87,199	2.37	05-2034	55-R1 *	(3)	139,298	3.79	52,099
TOTAL CRYSTAL RIVER RAIL CARS	*3,679,303.33*	*2,547,149*				*87,199*	*2.37*				*139,298*	*3.79*	*52,099*
TOTAL CRYSTAL RIVER STEAM PLANT	***2,824,927,208.82***	***1,641,117,914***				***134,937,768***	***4.78***				***138,648,463***	***4.91***	***3,710,695***
TOTAL STEAM PRODUCTION PLANT	**3,324,037,278.62**	**1,953,970,333**				**174,948,163**	**5.26**				**151,256,545**	**4.55**	**(23,691,618)**
COMBINED CYCLE PRODUCTION PLANT													
BARTOW COMBINED CYCLE PLANT													
BARTOW UNIT 4													
341.00 STRUCTURES AND IMPROVEMENTS	93,720,402.36	51,298,938	06-2049	85-R1.5 *	(2)	4,076,838	4.35	06-2054	85-R1.5 *	(3)	1,627,089	1.74	(2,449,749)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45,199,468.01	23,688,627	06-2049	50-R1 *	(3)	3,118,763	6.90	06-2054	50-R1 *	(7)	979,159	2.17	(2,139,604)
343.00 PRIME MOVERS - GENERAL	429,196,967.18	66,827,715	06-2049	40-R0.5 *	0	13,905,982	3.24	06-2054	40-R0.5 *	0	15,632,841	3.64	1,726,859
343.10 PRIME MOVERS - ROTABLE PARTS	95,956,331.77	14,543,791	06-2049	7-L0.5 *	40	14,124,772	14.72	06-2054	7-L0.5 *	40	7,642,985	7.97	(6,481,787)
344.00 GENERATORS	44,532,239.27	(4,140,696)	06-2049	65-R1 *	(1)	1,567,535	3.52	06-2054	65-R1 *	(3)	1,856,307	4.17	288,772
345.00 ACCESSORY ELECTRIC EQUIPMENT	40,947,935.84	13,880,162	06-2049	60-S0 *	(2)	1,162,921	2.84	06-2054	60-S0 *	(4)	1,109,613	2.71	(53,308)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	32,981,650.53	5,694,422	06-2049	35-R1.5 *	(5)	1,329,161	4.03	06-2054	35-R1.5 *	(8)	1,301,686	3.95	(27,475)
TOTAL BARTOW UNIT 4	*782,534,994.96*	*171,792,958*				*39,285,972*	*5.02*				*30,149,680*	*3.85*	*(9,136,292)*
TOTAL BARTOW COMBINED CYCLE PLANT	***782,534,994.96***	***171,792,958***				***39,285,972***	***5.02***				***30,149,680***	***3.85***	***(9,136,292)***
CITRUS COMBINED CYCLE PLANT													
CITRUS UNITS 1 AND 2													
341.00 STRUCTURES AND IMPROVEMENTS	128,195,624.36	103,677,217	06-2058	85-R1.5 *	(2)	3,448,462	2.69	06-2063	85-R1.5 *	(3)	785,714	0.61	(2,662,748)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	221,420,258.97	13,028,918	06-2058	50-R1 *	(3)	6,642,608	3.00	06-2063	50-R1 *	(7)	6,933,749	3.13	291,141
343.00 PRIME MOVERS - GENERAL	741,297,562.49	61,953,476	06-2058	40-R0.5 *	0	23,869,782	3.22	06-2063	40-R0.5 *	0	23,401,450	3.16	(468,332)
343.10 PRIME MOVERS - ROTABLE PARTS	183,280,962.27	18,257,079	06-2058	7-L0.5 *	40	16,825,192	9.18	06-2063	7-L0.5 *	40	18,527,576	10.11	1,702,384
344.00 GENERATORS	16,200,754.81	15,449,583	06-2058	65-R1 *	(1)	452,001	2.79	06-2063	65-R1 *	(3)	36,144	0.22	(415,857)
345.00 ACCESSORY ELECTRIC EQUIPMENT	121,897,707.10	30,240,468	06-2058	60-S0 *	(2)	3,474,085	2.85	06-2063	60-S0 *	(4)	2,904,126	2.38	(569,959)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	6,228,549.19	6,297,979	06-2058	35-R1.5 *	(5)	209,279	3.36	06-2063	35-R1.5 *	(8)	15,316	0.25	(193,963)
TOTAL CITRUS UNITS 1 AND 2	*1,418,521,419.19*	*248,904,720*				*54,921,409*	*3.87*				*52,604,075*	*3.71*	*(2,317,334)*
TOTAL CITRUS COMBINED CYCLE PLANT	***1,418,521,419.19***	***248,904,720***				***54,921,409***	***3.87***				***52,604,075***	***3.71***	***(2,317,334)***
OSPREY COMBINED CYCLE PLANT													
OSPREY ENERGY CENTER													
341.00 STRUCTURES AND IMPROVEMENTS	90,271,971.20	42,640,950	06-2044	85-R1.5 *	(2)	1,796,412	1.99	06-2049	85-R1.5 *	(3)	2,148,493	2.38	352,081
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	14,540,305.99	8,238,264	06-2044	50-R1 *	(3)	327,157	2.25	06-2049	50-R1 *	(7)	344,626	2.37	17,469
343.00 PRIME MOVERS - GENERAL	185,111,622.50	86,887,630	06-2044	40-R0.5 *	0	5,331,215	2.88	06-2049	40-R0.5 *	0	4,970,850	2.69	(360,365)
343.10 PRIME MOVERS - ROTABLE PARTS	58,678,433.74	21,356,554	06-2044	7-L0.5 *	40	4,160,301	7.09	06-2049	7-L0.5 *	40	4,049,856	6.90	(110,445)
344.00 GENERATORS	33,184,504.84	16,656,177	06-2044	65-R1 *	(1)	803,065	2.42	06-2049	65-R1 *	(3)	781,617	2.36	(21,448)
345.00 ACCESSORY ELECTRIC EQUIPMENT	42,994,257.49	24,548,565	06-2044	60-S0 *	(2)	868,484	2.02	06-2049	60-S0 *	(4)	930,141	2.16	61,657
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	9,901,465.48	4,686,134	06-2044	35-R1.5 *	(5)	283,182	2.86	06-2049	35-R1.5 *	(8)	311,913	3.15	28,731
TOTAL OSPREY ENERGY CENTER	*434,682,561.24*	*205,014,273*				*13,569,816*	*3.12*				*13,537,496*	*3.11*	*(32,320)*
TOTAL OSPREY COMBINED CYCLE PLANT	***434,682,561.24***	***205,014,273***				***13,569,816***	***3.12***				***13,537,496***	***3.11***	***(32,320)***

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

			CURRENT DEPRECIATION RATES					PROPOSED DEPRECIATION RATES					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
HINES ENERGY COMBINED CYCLE PLANT													
HINES ENERGY COMPLEX UNIT 1													
341.00 STRUCTURES AND IMPROVEMENTS	68,493,890.37	33,743,452	06-2039	85-R1.5 *	(2)	2,267,148	3.31	06-2044	85-R1.5 *	(3)	1,954,607	2.85	(312,541)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	19,474,758.27	14,652,731	06-2039	50-R1 *	(3)	321,334	1.65	06-2044	50-R1 *	(7)	354,863	1.82	33,529
343.00 PRIME MOVERS - GENERAL	214,754,508.30	70,352,127	06-2039	40-R0.5 *	0	12,412,811	5.78	06-2044	40-R0.5 *	0	8,549,579	3.98	(3,863,232)
343.10 PRIME MOVERS - ROTABLE PARTS	91,643,841.96	19,580,222	06-2039	7-L0.5 *	40	12,096,987	13.20	06-2044	7-L0.5 *	40	8,763,882	9.56	(3,333,105)
344.00 GENERATORS	48,657,531.65	32,047,267	06-2039	65-R1 *	(1)	1,036,405	2.13	06-2044	65-R1 *	(3)	997,791	2.05	(38,614)
345.00 ACCESSORY ELECTRIC EQUIPMENT	59,828,131.76	22,943,438	06-2039	60-S0 *	(2)	2,315,349	3.87	06-2044	60-S0 *	(4)	2,149,853	3.59	(165,496)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	11,510,368.97	3,197,512	06-2039	35-R1.5 *	(5)	702,133	6.10	06-2044	35-R1.5 *	(8)	551,924	4.80	(150,209)
TOTAL HINES ENERGY COMPLEX UNIT 1	*514,363,031.28*	*196,516,749*				*31,152,167*	*6.06*				*23,322,499*	*4.53*	*(7,829,668)*
HINES ENERGY COMPLEX UNIT 2													
341.00 STRUCTURES AND IMPROVEMENTS	21,325,632.99	14,478,147	06-2043	85-R1.5 *	(2)	204,726	0.96	06-2048	85-R1.5 *	(3)	333,508	1.56	128,782
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	12,989,944.47	7,677,656	06-2043	50-R1 *	(3)	310,460	2.39	06-2048	50-R1 *	(7)	305,279	2.35	(5,181)
343.00 PRIME MOVERS - GENERAL	110,382,487.52	16,759,063	06-2043	40-R0.5 *	0	6,126,228	5.55	06-2048	40-R0.5 *	0	4,816,020	4.36	(1,310,208)
343.10 PRIME MOVERS - ROTABLE PARTS	66,184,577.50	6,460,399	06-2043	7-L0.5 *	40	8,233,361	12.44	06-2048	7-L0.5 *	40	8,050,932	12.16	(182,429)
344.00 GENERATORS	37,907,796.52	16,701,978	06-2043	65-R1 *	(1)	1,114,489	2.94	06-2048	65-R1 *	(3)	1,036,320	2.73	(78,169)
345.00 ACCESSORY ELECTRIC EQUIPMENT	19,333,719.67	8,234,157	06-2043	60-S0 *	(2)	726,948	3.76	06-2048	60-S0 *	(4)	566,186	2.93	(160,762)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	3,052,178.75	1,519,120	06-2043	35-R1.5 *	(5)	107,437	3.52	06-2048	35-R1.5 *	(8)	103,267	3.38	(4,170)
TOTAL HINES ENERGY COMPLEX UNIT 2	*271,176,337.42*	*71,830,522*				*16,823,649*	*6.20*				*15,211,512*	*5.61*	*(1,612,137)*
HINES ENERGY COMPLEX UNIT 3													
341.00 STRUCTURES AND IMPROVEMENTS	11,336,174.87	7,270,297	06-2045	85-R1.5 *	(2)	200,650	1.77	06-2050	85-R1.5 *	(3)	181,689	1.60	(18,961)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	15,089,457.52	10,319,149	06-2045	50-R1 *	(3)	(737,874)	(4.89)	06-2050	50-R1 *	(7)	264,965	1.76	1,002,839
343.00 PRIME MOVERS - GENERAL	128,203,896.82	26,505,555	06-2045	40-R0.5 *	0	7,435,826	5.80	06-2050	40-R0.5 *	0	4,915,338	3.83	(2,520,488)
343.10 PRIME MOVERS - ROTABLE PARTS	15,094,251.97	4,037,886	06-2045	7-L0.5 *	40	2,298,855	15.23	06-2050	7-L0.5 *	40	1,081,609	7.17	(1,217,246)
344.00 GENERATORS	54,825,570.98	32,522,285	06-2045	65-R1 *	(1)	1,178,750	2.15	06-2050	65-R1 *	(3)	1,029,139	1.88	(149,611)
345.00 ACCESSORY ELECTRIC EQUIPMENT	23,403,938.11	15,250,305	06-2045	60-S0 *	(2)	432,973	1.85	06-2050	60-S0 *	(4)	404,710	1.73	(28,263)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	2,666,136.13	1,010,375	06-2045	35-R1.5 *	(5)	83,450	3.13	06-2050	35-R1.5 *	(8)	92,208	3.46	8,758
TOTAL HINES ENERGY COMPLEX UNIT 3	*250,619,426.40*	*96,915,851*				*10,892,630*	*4.35*				*7,969,658*	*3.18*	*(2,922,972)*
HINES ENERGY COMPLEX UNIT 4													
341.00 STRUCTURES AND IMPROVEMENTS	15,099,834.63	7,908,846	06-2047	85-R1.5 *	(2)	298,977	1.98	06-2052	85-R1.5 *	(3)	292,425	1.94	(6,552)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,787,851.96	4,401,019	06-2047	50-R1 *	(3)	179,121	2.30	06-2052	50-R1 *	(7)	166,609	2.14	(12,512)
343.00 PRIME MOVERS - GENERAL	153,428,720.80	43,618,239	06-2047	40-R0.5 *	0	6,229,206	4.06	06-2052	40-R0.5 *	0	4,928,657	3.21	(1,300,549)
343.10 PRIME MOVERS - ROTABLE PARTS	57,837,107.77	9,872,050	06-2047	7-L0.5 *	40	7,154,450	12.37	06-2052	7-L0.5 *	40	5,445,223	9.41	(1,709,227)
344.00 GENERATORS	47,487,798.71	19,319,277	06-2047	65-R1 *	(1)	1,377,146	2.90	06-2052	65-R1 *	(3)	1,185,148	2.50	(191,998)
345.00 ACCESSORY ELECTRIC EQUIPMENT	26,914,929.67	12,940,118	06-2047	60-S0 *	(2)	705,171	2.62	06-2052	60-S0 *	(4)	621,445	2.31	(83,726)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	8,174,447.90	2,493,513	06-2047	35-R1.5 *	(5)	282,836	3.46	06-2052	35-R1.5 *	(8)	312,834	3.83	29,998
TOTAL HINES ENERGY COMPLEX UNIT 4	*316,730,691.44*	*100,553,062*				*16,226,907*	*5.12*				*12,952,341*	*4.09*	*(3,274,566)*
TOTAL HINES ENERGY COMBINED CYCLE PLANT	***1,352,889,486.54***	***465,816,183***				***75,095,353***	***5.55***				***59,456,010***	***4.39***	***(15,639,343)***
TIGER BAY COGENERATION													
TIGER BAY COGENERATION													
341.00 STRUCTURES AND IMPROVEMENTS	12,006,530.32	8,106,913	06-2035	85-R1.5 *	(2)	401,018	3.34	06-2040	85-R1.5 *	(3)	283,609	2.36	(117,409)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	5,651,591.32	1,779,901	06-2035	50-R1 *	(3)	543,683	9.62	06-2040	50-R1 *	(7)	294,297	5.21	(249,386)
343.00 PRIME MOVERS - GENERAL	31,070,538.39	8,354,183	06-2035	40-R0.5 *	0	2,010,264	6.47	06-2040	40-R0.5 *	0	1,643,731	5.29	(366,533)
343.10 PRIME MOVERS - ROTABLE PARTS	23,463,898.76	4,677,274	06-2035	7-L0.5 *	40	3,001,033	12.79	06-2040	7-L0.5 *	40	3,574,550	15.23	573,517
344.00 GENERATORS	10,850,295.54	3,629,662	06-2035	65-R1 *	(1)	836,558	7.71	06-2040	65-R1 *	(3)	515,095	4.75	(321,463)
345.00 ACCESSORY ELECTRIC EQUIPMENT	9,033,735.87	3,371,715	06-2035	60-S0 *	(2)	731,733	8.10	06-2040	60-S0 *	(4)	411,714	4.56	(320,019)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,745,446.32	1,142,887	06-2035	35-R1.5 *	(5)	78,894	4.52	06-2040	35-R1.5 *	(8)	58,257	3.34	(20,637)
TOTAL TIGER BAY COGENERATION	*93,822,036.52*	*31,062,534*				*7,603,183*	*8.10*				*6,781,253*	*7.23*	*(821,930)*
TOTAL TIGER BAY COGENERATION	***93,822,036.52***	***31,062,534***				***7,603,183***	***8.10***				***6,781,253***	***7.23***	***(821,930)***
TOTAL COMBINED CYCLE PRODUCTION PLANT	**4,082,450,498.45**	**1,122,590,669**				**190,475,733**	**4.67**				**162,528,514**	**3.98**	**(27,947,219)**
SIMPLE CYCLE PRODUCTION PLANT													
BARTOW PEAKING													
BARTOW UNITS 1 AND 3													
341.00 STRUCTURES AND IMPROVEMENTS	2,024,591.17	1,315,448	06-2034	85-R1.5 *	(1)	152,249	7.52	06-2034	85-R1.5 *	(1)	77,843	3.84	(74,406)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	3,417,718.30	2,598,896	06-2034	50-R1 *	(2)	197,202	5.77	06-2034	50-R1 *	(3)	102,146	2.99	(95,056)
343.00 PRIME MOVERS - GENERAL	11,261,919.71	5,760,507	06-2034	40-R0.5 *	0	718,510	6.38	06-2034	40-R0.5 *	0	633,803	5.63	(84,707)
344.00 GENERATORS	4,817,918.84	4,747,170	06-2034	65-R1 *	(1)	177,781	3.69	06-2034	65-R1 *	(2)	18,650	0.39	(159,131)
345.00 ACCESSORY ELECTRIC EQUIPMENT	3,846,400.78	2,067,271	06-2034	60-S0 *	(1)	231,553	6.02	06-2034	60-S0 *	(2)	202,848	5.27	(28,705)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	288,160.46	67,903	06-2034	35-R1.5 *	(2)	15,417	5.35	06-2034	35-R1.5 *	(2)	25,890	8.98	10,473
TOTAL BARTOW UNITS 1 AND 3	*25,656,709.26*	*16,557,195*				*1,492,712*	*5.82*				*1,061,180*	*4.14*	*(431,532)*
BARTOW UNITS 2 AND 4													
341.00 STRUCTURES AND IMPROVEMENTS	606,249.55	176,005	06-2027	85-R1.5 *	(1)	20,067	3.31	06-2027	85-R1.5 *	(1)	175,224	28.90	155,157
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	167,146.01	163,225	06-2027	50-R1 *	(2)	6,719	4.02	06-2027	50-R1 *	(3)	3,647	2.18	(3,072)
343.00 PRIME MOVERS - GENERAL	13,744,069.55	6,590,932	06-2027	40-R0.5 *	0	1,404,644	10.22	06-2027	40-R0.5 *	0	2,907,779	21.16	1,503,135
344.00 GENERATORS	2,494,674.18	2,011,967	06-2027	65-R1 *	(1)	116,252	4.66	06-2027	65-R1 *	(2)	214,758	8.61	98,506
345.00 ACCESSORY ELECTRIC EQUIPMENT	298,332.54	187,256	06-2027	60-S0 *	(1)	15,513	5.20	06-2027	60-S0 *	(2)	47,195	15.82	31,682
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	4,304,654.21	396,020	06-2027	35-R1.5 *	(2)	263,014	6.11	06-2027	35-R1.5 *	(2)	1,610,777	37.42	1,347,763
TOTAL BARTOW UNITS 2 AND 4	*21,615,126.04*	*9,525,405*				*1,826,209*	*8.45*				*4,959,380*	*22.94*	*3,133,171*
TOTAL BARTOW PEAKING	***47,271,835.30***	***26,082,600***				***3,318,921***	***7.02***				***6,020,560***	***12.74***	***2,701,639***

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

			CURRENT DEPRECIATION RATES					PROPOSED DEPRECIATION RATES					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
BAYBORO PEAKING													
BAYBORO UNITS 1 THROUGH 4													
341.00 STRUCTURES AND IMPROVEMENTS	2,000,348.95	1,691,582	06-2024	85-R1.5 *	(1)	186,833	9.34	09-2026	85-R1.5 *	(1)	187,869	9.39	1,036
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,918,698.73	1,794,050	06-2024	50-R1 *	(2)	165,392	8.62	09-2026	50-R1 *	(3)	105,324	5.49	(60,068)
343.00 PRIME MOVERS - GENERAL	17,747,817.33	12,896,824	06-2024	40-R0.5 *	0	257,343	1.45	09-2026	40-R0.5 *	0	2,820,345	15.89	2,563,002
344.00 GENERATORS	3,896,002.33	3,649,362	06-2024	65-R1 *	(1)	337,394	8.66	09-2026	65-R1 *	(2)	186,529	4.79	(150,865)
345.00 ACCESSORY ELECTRIC EQUIPMENT	1,512,283.31	986,008	06-2024	60-S0 *	(1)	132,930	8.79	09-2026	60-S0 *	(2)	319,840	21.15	186,910
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	577,277.04	491,024	06-2024	35-R1.5 *	(2)	60,037	10.40	09-2026	35-R1.5 *	(2)	56,531	9.79	(3,506)
TOTAL BAYBORO UNITS 1 THROUGH 4	*27,652,427.69*	*21,508,851*				*1,139,929*	*4.12*				*3,676,438*	*13.30*	*2,536,509*
TOTAL BARTOW PEAKING	***27,652,427.69***	***21,508,851***				***1,139,929***	***4.12***				***3,676,438***	***13.30***	***2,536,509***
DEBARY PEAKING													
DEBARY UNITS 2 THROUGH 6													
341.00 STRUCTURES AND IMPROVEMENTS	6,210,264.52	5,662,450	06-2027	85-R1.5 *	(1)	276,978	4.46	06-2027	85-R1.5 *	(1)	244,947	3.94	(32,031)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,282,898.23	7,836,776	06-2027	50-R1 *	(2)	567,616	5.52	06-2027	50-R1 *	(3)	1,119,760	10.89	552,144
343.00 PRIME MOVERS - GENERAL	26,653,742.68	28,301,450	06-2027	40-R0.5 *	0	855,585	3.21	06-2027	40-R0.5 *	0	(680,871)	(2.55)	(1,536,456)
344.00 GENERATORS	7,868,742.04	8,807,544	06-2027	65-R1 *	(1)	484,715	6.16	06-2027	65-R1 *	(2)	(316,368)	(4.02)	(801,083)
345.00 ACCESSORY ELECTRIC EQUIPMENT	7,007,923.65	6,372,188	06-2027	60-S0 *	(1)	361,609	5.16	06-2027	60-S0 *	(2)	314,127	4.48	(47,482)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,489,071.94	827,655	06-2027	35-R1.5 *	(2)	61,796	4.15	06-2027	35-R1.5 *	(2)	282,122	18.95	220,326
TOTAL DEBARY UNITS 2 THROUGH 6	*59,512,643.06*	*57,808,063*				*2,608,299*	*4.38*				*963,717*	*1.62*	*(1,644,582)*
DEBARY UNITS 7 THROUGH 10													
341.00 STRUCTURES AND IMPROVEMENTS	7,382,724.97	3,506,430	06-2037	85-R1.5 *	(1)	82,687	1.12	06-2037	85-R1.5 *	(1)	322,459	4.37	239,772
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,691,276.44	6,511,849	06-2037	50-R1 *	(2)	232,277	3.02	06-2037	50-R1 *	(3)	122,517	1.59	(109,760)
343.00 PRIME MOVERS - GENERAL	77,093,329.41	62,080,457	06-2037	40-R0.5 *	0	701,549	0.91	06-2037	40-R0.5 *	0	1,348,865	1.75	647,316
343.10 PRIME MOVERS - ROTABLE PARTS	3,349,494.52	30,957	06-2037	40-R0.5 *	0	30,480	0.91	06-2037	40-R0.5 *	0	283,394	8.46	252,914
344.00 GENERATORS	19,827,030.40	17,259,259	06-2037	65-R1 *	(1)	170,512	0.86	06-2037	65-R1 *	(2)	249,311	1.26	78,799
345.00 ACCESSORY ELECTRIC EQUIPMENT	7,731,185.34	4,420,012	06-2037	60-S0 *	(1)	84,270	1.09	06-2037	60-S0 *	(2)	290,268	3.75	205,998
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,136,152.60	760,616	06-2037	35-R1.5 *	(2)	(227)	(0.02)	06-2037	35-R1.5 *	(2)	36,740	3.23	36,967
TOTAL DEBARY UNITS 7 THROUGH 10	*124,211,193.68*	*94,569,579*				*1,301,548*	*1.05*				*2,653,554*	*2.14*	*1,352,006*
TOTAL DEBARY PEAKING	***183,723,836.74***	***152,377,642***				***3,909,847***	***2.13***				***3,617,271***	***1.97***	***(292,576)***
INTERCESSION CITY PEAKING													
INTERCESSION CITY UNITS 1 THROUGH 6													
341.00 STRUCTURES AND IMPROVEMENTS	6,460,210.45	3,595,743	06-2034	85-R1.5 *	(1)	158,921	2.46	06-2034	85-R1.5 *	(1)	312,935	4.84	154,014
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,218,886.58	2,409,027	06-2034	50-R1 *	(2)	(347,014)	(5.58)	06-2034	50-R1 *	(3)	438,686	7.05	785,700
343.00 PRIME MOVERS - GENERAL	30,598,075.01	19,198,773	06-2034	40-R0.5 *	0	1,768,569	5.78	06-2034	40-R0.5 *	0	1,316,317	4.30	(452,252)
344.00 GENERATORS	6,033,618.14	3,137,153	06-2034	65-R1 *	(1)	158,684	2.63	06-2034	65-R1 *	(2)	327,594	5.43	168,910
345.00 ACCESSORY ELECTRIC EQUIPMENT	6,260,250.93	3,936,378	06-2034	60-S0 *	(1)	327,411	5.23	06-2034	60-S0 *	(2)	267,075	4.27	(60,336)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,918,301.38	1,309,752	06-2034	35-R1.5 *	(2)	105,698	5.51	06-2034	35-R1.5 *	(2)	73,015	3.81	(32,683)
TOTAL INTERCESSION CITY UNITS 1 THROUGH 6	*57,489,342.49*	*33,586,826*				*2,172,269*	*3.78*				*2,735,622*	*4.76*	*563,353*
INTERCESSION CITY UNITS 7 THROUGH 10													
341.00 STRUCTURES AND IMPROVEMENTS	10,458,627.44	7,714,104	06-2038	85-R1.5 *	(1)	191,393	1.83	06-2038	85-R1.5 *	(1)	217,489	2.08	26,096
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	8,223,597.18	5,773,029	06-2038	50-R1 *	(2)	207,235	2.52	06-2038	50-R1 *	(3)	218,403	2.66	11,168
343.00 PRIME MOVERS - GENERAL	79,743,189.19	45,202,287	06-2038	40-R0.5 *	0	2,432,167	3.05	06-2038	40-R0.5 *	0	2,820,702	3.54	388,535
343.10 PRIME MOVERS - ROTABLE PARTS	6,316,102.71	1,470,902	06-2038	40-R0.5 *	0	192,641	3.05	06-2038	40-R0.5 *	0	427,764	6.77	235,123
344.00 GENERATORS	18,478,191.88	13,314,144	06-2038	65-R1 *	(1)	430,542	2.33	06-2038	65-R1 *	(2)	432,313	2.34	1,771
345.00 ACCESSORY ELECTRIC EQUIPMENT	7,326,245.55	4,535,590	06-2038	60-S0 *	(1)	253,488	3.46	06-2038	60-S0 *	(2)	230,729	3.15	(22,759)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,091,865.99	584,326	06-2038	35-R1.5 *	(2)	46,623	4.27	06-2038	35-R1.5 *	(2)	46,234	4.23	(389)
TOTAL INTERCESSION CITY UNITS 7 THROUGH 10	*131,637,819.94*	*78,594,381*				*3,754,089*	*2.85*				*4,393,634*	*3.34*	*639,545*
INTERCESSION CITY UNIT 11													
341.00 STRUCTURES AND IMPROVEMENTS	2,123,396.81	1,680,725	06-2042	85-R1.5 *	(1)	19,748	0.93	06-2042	85-R1.5 *	(1)	27,531	1.30	7,783
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,930,623.85	1,366,232	06-2042	50-R1 *	(2)	19,692	1.02	06-2042	50-R1 *	(3)	40,279	2.09	20,587
343.00 PRIME MOVERS - GENERAL	25,196,412.69	20,778,342	06-2042	40-R0.5 *	0	360,309	1.43	06-2042	40-R0.5 *	0	298,317	1.18	(61,992)
344.00 GENERATORS	4,183,183.34	3,644,123	06-2042	65-R1 *	(1)	48,107	1.15	06-2042	65-R1 *	(2)	38,298	0.92	(9,809)
345.00 ACCESSORY ELECTRIC EQUIPMENT	4,785,400.55	3,843,938	06-2042	60-S0 *	(1)	76,088	1.59	06-2042	60-S0 *	(2)	65,769	1.37	(10,319)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	257,487.22	181,396	06-2042	35-R1.5 *	(2)	6,283	2.44	06-2042	35-R1.5 *	(2)	5,669	2.20	(614)
TOTAL INTERCESSION CITY UNIT 11	*38,476,504.46*	*31,494,756*				*530,227*	*1.38*				*475,863*	*1.24*	*(54,364)*
INTERCESSION CITY UNITS 12 THROUGH 14													
341.00 STRUCTURES AND IMPROVEMENTS	1,569,822.33	766,453	06-2045	85-R1.5 *	(1)	39,873	2.54	06-2045	85-R1.5 *	(1)	41,619	2.65	1,746
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	5,206,204.18	922,711	06-2045	50-R1 *	(2)	220,743	4.24	06-2045	50-R1 *	(3)	242,871	4.67	22,128
343.00 PRIME MOVERS - GENERAL	65,026,103.12	28,529,494	06-2045	40-R0.5 *	0	1,430,574	2.20	06-2045	40-R0.5 *	0	2,103,551	3.23	672,977
343.10 PRIME MOVERS - ROTABLE PARTS	1,410,035.11	46,531	06-2045	40-R0.5 *	0	31,021	2.20	06-2045	40-R0.5 *	0	74,672	5.30	43,651
344.00 GENERATORS	17,766,619.90	10,675,555	06-2045	65-R1 *	(1)	254,063	1.43	06-2045	65-R1 *	(2)	392,329	2.21	138,266
345.00 ACCESSORY ELECTRIC EQUIPMENT	9,840,894.39	4,625,172	06-2045	60-S0 *	(1)	174,184	1.77	06-2045	60-S0 *	(2)	289,131	2.94	114,947
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	158,572.66	153,275	06-2045	35-R1.5 *	(2)	4,424	2.79	06-2045	35-R1.5 *	(2)	477	0.30	(3,947)
TOTAL INTERCESSION CITY UNITS 12 THROUGH 14	*100,978,251.69*	*45,719,192*				*2,154,882*	*2.13*				*3,144,650*	*3.11*	*989,768*
TOTAL INTERCESSION CITY PEAKING	***328,581,918.58***	***189,395,155***				***8,611,467***	***2.62***				***10,749,769***	***3.27***	***2,138,302***
SUWANNEE RIVER PEAKING													
SUWANNEE RIVER UNITS 1 THROUGH 3													
341.00 STRUCTURES AND IMPROVEMENTS	7,469,390.35	2,703,023	06-2034	85-R1.5 *	(1)	245,743	3.29	06-2034	85-R1.5 *	(1)	516,105	6.91	270,362
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,575,734.49	4,686,311	06-2034	50-R1 *	(2)	252,272	3.33	06-2034	50-R1 *	(3)	345,532	4.56	93,260
343.00 PRIME MOVERS - GENERAL	29,049,006.77	16,041,523	06-2034	40-R0.5 *	0	1,220,058	4.20	06-2034	40-R0.5 *	0	1,508,989	5.19	288,931
344.00 GENERATORS	7,189,869.25	4,183,247	06-2034	65-R1 *	(1)	308,445	4.29	06-2034	65-R1 *	(2)	342,809	4.77	34,364

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

			CURRENT DEPRECIATION RATES					PROPOSED DEPRECIATION RATES					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
345.00 ACCESSORY ELECTRIC EQUIPMENT	6,570,026.31	1,858,313	06-2034	60-S0 *	(1)	231,265	3.52	06-2034	60-S0 *	(2)	524,714	7.99	293,449
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	2,247,634.80	488,684	06-2034	35-R1.5 *	(2)	74,397	3.31	06-2034	35-R1.5 *	(2)	199,547	8.88	125,150
TOTAL SUWANNEE RIVER UNITS 1 THROUGH 3	*60,101,661.97*	*29,961,101*				*2,332,180*	*3.88*				*3,437,696*	*5.72*	*1,105,516*
TOTAL SUWANNEE RIVER PEAKING	***60,101,661.97***	***29,961,101***				***2,332,180***	***3.88***				***3,437,696***	***5.72***	***1,105,516***
UNIVERSITY OF FLORIDA COGENERATION													
UNIVERSITY OF FLORIDA COGENERATION													
341.00 STRUCTURES AND IMPROVEMENTS	8,662,876.52	8,533,293	10-2027	85-R1.5 *	(1)	498,115	5.75	10-2041	85-R1.5 *	(1)	13,248	0.15	(484,867)
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,655,241.68	5,056,879	10-2027	50-R1 *	(2)	653,545	9.82	10-2041	50-R1 *	(3)	118,917	1.79	(534,628)
343.00 PRIME MOVERS - GENERAL	32,206,792.65	17,925,854	10-2027	40-R0.5 *	0	7,368,914	22.88	10-2041	40-R0.5 *	0	959,741	2.98	(6,409,173)
344.00 GENERATORS	5,811,572.48	1,708,812	10-2027	65-R1 *	(1)	327,192	5.63	10-2041	65-R1 *	(2)	264,182	4.55	(63,010)
345.00 ACCESSORY ELECTRIC EQUIPMENT	6,393,743.95	3,631,391	10-2027	60-S0 *	(1)	407,921	6.38	10-2041	60-S0 *	(2)	186,466	2.92	(221,455)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,566,762.66	1,047,359	10-2027	35-R1.5 *	(2)	125,811	8.03	10-2041	35-R1.5 *	(2)	40,645	2.59	(85,166)
TOTAL UNIVERSITY OF FLORIDA COGENERATION	*61,296,989.94*	*37,903,588*				*9,381,498*	*15.30*				*1,583,199*	*2.58*	*(7,798,299)*
TOTAL UNIVERSITY OF FLORIDA COGENERATION	***61,296,989.94***	***37,903,588***				***9,381,498***	***15.30***				***1,583,199***	***2.58***	***(7,798,299)***
TOTAL SIMPLE CYCLE PRODUCTION PLANT	**708,628,670.22**	**457,228,937**				**28,693,842**	**4.05**				**29,084,933**	**4.10**	**391,091**
SOLAR PRODUCTION PLANT													
OSCEOLA													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	85,628.96	24,255	06-2046	SQUARE *	0	17,785	20.77	06-2051	SQUARE *	0	2,315	2.70	(15,470)
344.66 GENERATORS - SOLAR	6,419,235.56	1,527,160	06-2046	SQUARE *	0	213,761	3.33	06-2051	SQUARE *	0	184,816	2.88	(28,945)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	1,106,226.34	260,386	06-2046	SQUARE *	0	36,837	3.33	06-2051	SQUARE *	0	31,955	2.89	(4,882)
TOTAL OSCEOLA	*7,611,090.86*	*1,811,800*				*268,383*	*3.53*				*219,086*	*2.88*	*(49,297)*
PERRY													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	346,780.78	62,489	06-2046	SQUARE *	0	13,178	3.80	06-2051	SQUARE *	0	10,712	3.09	(2,466)
344.66 GENERATORS - SOLAR	9,270,669.08	2,535,329	06-2046	SQUARE *	0	311,494	3.36	06-2051	SQUARE *	0	254,452	2.74	(57,042)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	1,495,673.04	319,683	06-2046	SQUARE *	0	50,255	3.36	06-2051	SQUARE *	0	44,427	2.97	(5,828)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	14,558.00	3,440	06-2046	SQUARE *	0	517	3.55	06-2051	SQUARE *	0	419	2.88	(98)
TOTAL PERRY	*11,127,680.90*	*2,920,940*				*375,444*	*3.37*				*310,010*	*2.79*	*(65,434)*
HAMILTON													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	2,579,609.22	510,053	06-2048	SQUARE *	0	81,000	3.14	06-2053	SQUARE *	0	72,693	2.82	(8,307)
344.66 GENERATORS - SOLAR	97,250,268.38	19,572,646	06-2048	SQUARE *	0	3,306,509	3.40	06-2053	SQUARE *	0	2,728,403	2.81	(578,106)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	10,772,233.22	1,881,141	06-2048	SQUARE *	0	366,256	3.40	06-2053	SQUARE *	0	312,187	2.90	(54,069)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	73,504.54	105,217	06-2048	SQUARE *	0	2,499	3.40	06-2053	SQUARE *	0	(1,113)	(1.51)	(3,612)
TOTAL HAMILTON	*110,675,615.36*	*22,069,058*				*3,756,264*	*3.39*				*3,112,170*	*2.81*	*(644,094)*
SUWANNEE													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	60,101.96	14,133	06-2047	SQUARE *	0	2,043	3.40	06-2052	SQUARE *	0	1,673	2.78	(370)
344.66 GENERATORS - SOLAR	14,110,951.20	3,484,481	06-2047	SQUARE *	0	478,361	3.39	06-2052	SQUARE *	0	386,839	2.74	(91,522)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	2,543,836.04	457,988	06-2047	SQUARE *	0	85,982	3.38	06-2052	SQUARE *	0	75,932	2.98	(10,050)
TOTAL SUWANNEE	*16,714,889.20*	*3,956,602*				*566,386*	*3.39*				*464,444*	*2.78*	*(101,942)*
DEBARY													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	2,406,595.22	565,428	06-2050	SQUARE *	0	80,862	3.36	06-2055	SQUARE *	0	60,426	2.51	(20,436)
344.66 GENERATORS - SOLAR	74,033,927.89	10,971,830	06-2050	SQUARE *	0	2,487,540	3.36	06-2055	SQUARE *	0	2,069,645	2.80	(417,895)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	10,721,272.50	1,836,370	06-2050	SQUARE *	0	360,235	3.36	06-2055	SQUARE *	0	291,595	2.72	(68,640)
TOTAL DEBARY	*87,161,795.61*	*13,373,628*				*2,928,637*	*3.36*				*2,421,666*	*2.78*	*(506,971)*
LAKE PLACID													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	2,613,404.17	430,102	06-2049	SQUARE *	0	88,594	3.39	06-2054	SQUARE *	0	74,086	2.83	(14,508)
344.66 GENERATORS - SOLAR	45,157,987.58	7,696,433	06-2049	SQUARE *	0	1,530,856	3.39	06-2054	SQUARE *	0	1,271,176	2.81	(259,680)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	11,603,522.09	1,819,703	06-2049	SQUARE *	0	393,359	3.39	06-2054	SQUARE *	0	331,993	2.86	(61,366)
TOTAL LAKE PLACID	*59,374,913.84*	*9,946,238*				*2,012,809*	*3.39*				*1,677,255*	*2.82*	*(335,554)*
TRENTON													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	6,242,044.90	1,032,699	06-2049	SQUARE *	0	212,230	3.40	06-2054	SQUARE *	0	176,768	2.83	(35,462)
344.66 GENERATORS - SOLAR	75,345,223.17	13,121,635	06-2049	SQUARE *	0	2,561,738	3.40	06-2054	SQUARE *	0	2,111,421	2.80	(450,317)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	15,840,878.87	2,183,325	06-2049	SQUARE *	0	538,590	3.40	06-2054	SQUARE *	0	463,439	2.93	(75,151)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	64,881.13	5,499	06-2049	SQUARE *	0	2,206	3.40	06-2054	SQUARE *	0	2,010	3.10	(196)
TOTAL TRENTON	*97,493,028.07*	*16,343,158*				*3,314,764*	*3.40*				*2,753,638*	*2.82*	*(561,126)*
COLUMBIA													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	8,690,697.13	993,144	06-2050	SQUARE *	0	291,138	3.35	06-2055	SQUARE *	0	252,627	2.91	(38,511)
344.66 GENERATORS - SOLAR	87,196,878.11	13,937,474	06-2050	SQUARE *	0	2,929,815	3.36	06-2055	SQUARE *	0	2,404,313	2.76	(525,502)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	8,985,123.89	1,419,889	06-2050	SQUARE *	0	301,002	3.35	06-2055	SQUARE *	0	248,285	2.76	(52,717)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	10,573.15	1,385	06-2050	SQUARE *	0	354	3.35	06-2055	SQUARE *	0	302	2.86	(52)
TOTAL COLUMBIA	*104,883,272.28*	*16,351,892*				*3,522,309*	*3.36*				*2,905,527*	*2.77*	*(616,782)*
DUETTE													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	6,931,894.09	970,099	06-2051	SQUARE *	0	230,832	3.33	06-2056	SQUARE *	0	189,444	2.73	(41,388)
344.66 GENERATORS - SOLAR	83,728,381.62	8,482,336	06-2051	SQUARE *	0	2,788,155	3.33	06-2056	SQUARE *	0	2,391,041	2.86	(397,114)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	7,251,594.77	1,013,419	06-2051	SQUARE *	0	241,478	3.33	06-2056	SQUARE *	0	198,226	2.73	(43,252)
TOTAL DUETTE	*97,911,870.48*	*10,465,853*				*3,260,465*	*3.33*				*2,778,711*	*2.84*	*(481,754)*

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

			CURRENT DEPRECIATION RATES					PROPOSED DEPRECIATION RATES					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
SANTA FE													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	10,043,404.40	1,455,113	06-2051	SQUARE *	0	334,445	3.33	06-2056	SQUARE *	0	272,904	2.72	(61,541)
344.66 GENERATORS - SOLAR	84,537,374.36	10,233,025	06-2051	SQUARE *	0	2,815,095	3.33	06-2056	SQUARE *	0	2,361,117	2.79	(453,978)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	8,805,821.91	1,275,809	06-2051	SQUARE *	0	293,234	3.33	06-2056	SQUARE *	0	239,276	2.72	(53,958)
TOTAL SANTA FE	*103,386,600.67*	*12,963,948*				*3,442,774*	*3.33*				*2,873,297*	*2.78*	*(569,477)*
TWIN RIVERS													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	7,305,874.14	1,080,887	06-2051	SQUARE *	0	243,286	3.33	06-2056	SQUARE *	0	197,807	2.71	(45,479)
344.66 GENERATORS - SOLAR	67,787,978.36	7,084,700	06-2051	SQUARE *	0	2,257,340	3.33	06-2056	SQUARE *	0	1,928,925	2.85	(328,415)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	19,089,172.67	2,824,198	06-2051	SQUARE *	0	635,669	3.33	06-2056	SQUARE *	0	516,841	2.71	(118,828)
TOTAL TWIN RIVERS	*94,183,025.17*	*10,989,785*				*3,136,295*	*3.33*				*2,643,573*	*2.81*	*(492,722)*
ST PETE PIER													
344.66 GENERATORS - SOLAR	1,452,082.97	222,865	06-2049	SQUARE *	0	49,226	3.39	06-2054	SQUARE *	0	41,711	2.87	(7,515)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	93,671.18	14,377	06-2049	SQUARE *	0	3,175	3.39	06-2054	SQUARE *	0	2,691	2.87	(484)
TOTAL ST PETE PIER	*1,545,754.15*	*237,242*				*52,401*	*3.39*				*44,402*	*2.87*	*(7,999)*
BAY TRAIL													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	13,057,220.46	1,044,332	06-2052	SQUARE *	0	434,805	3.33	06-2057	SQUARE *	0	369,969	2.83	(64,836)
344.66 GENERATORS - SOLAR	67,565,184.36	5,403,944	06-2052	SQUARE *	0	2,249,921	3.33	06-2057	SQUARE *	0	1,914,421	2.83	(335,500)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	26,988,429.25	2,158,567	06-2052	SQUARE *	0	898,715	3.33	06-2057	SQUARE *	0	764,702	2.83	(134,013)
TOTAL BAY TRAIL	*107,610,834.07*	*8,606,842*				*3,583,441*	*3.33*				*3,049,092*	*2.83*	*(534,349)*
FORT GREEN													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	10,321,964.99	856,466	06-2052	SQUARE *	0	343,721	3.33	06-2057	SQUARE *	0	291,515	2.82	(52,206)
344.66 GENERATORS - SOLAR	86,882,074.88	7,209,046	06-2052	SQUARE *	0	2,893,173	3.33	06-2057	SQUARE *	0	2,453,743	2.82	(439,430)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	9,050,057.31	750,929	06-2052	SQUARE *	0	301,367	3.33	06-2057	SQUARE *	0	255,594	2.82	(45,773)
TOTAL FORT GREEN	*106,254,097.18*	*8,816,440*				*3,538,261*	*3.33*				*3,000,852*	*2.82*	*(537,409)*
SANDY CREEK													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	8,845,437.26	735,011	06-2052	SQUARE *	0	294,553	3.33	06-2057	SQUARE *	0	249,782	2.82	(44,771)
344.66 GENERATORS - SOLAR	74,453,841.01	6,186,737	06-2052	SQUARE *	0	2,479,313	3.33	06-2057	SQUARE *	0	2,102,467	2.82	(376,846)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	7,755,472.34	644,440	06-2052	SQUARE *	0	258,257	3.33	06-2057	SQUARE *	0	219,003	2.82	(39,254)
TOTAL SANDY CREEK	*91,054,750.61*	*7,566,188*				*3,032,123*	*3.33*				*2,571,252*	*2.82*	*(460,871)*
CHARLIE CREEK													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	9,148,229.52	698,254	06-2052	SQUARE *	0	304,636	3.33	06-2057	SQUARE *	0	260,239	2.84	(44,397)
344.66 GENERATORS - SOLAR	75,166,699.80	5,716,575	06-2052	SQUARE *	0	2,503,051	3.33	06-2057	SQUARE *	0	2,138,901	2.85	(364,150)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	13,760,900.37	1,050,324	06-2052	SQUARE *	0	458,238	3.33	06-2057	SQUARE *	0	391,456	2.84	(66,782)
TOTAL CHARLIE CREEK	*98,075,829.69*	*7,465,153*				*3,265,925*	*3.33*				*2,790,596*	*2.85*	*(475,329)*
NEW SOLAR 2023													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	32,471,053.95	1,621,929	06-2053	SQUARE *	0	1,081,286	3.33	06-2058	SQUARE *	0	921,695	2.84	(159,591)
344.66 GENERATORS - SOLAR	348,114,658.77	17,388,327	06-2053	SQUARE *	0	11,592,218	3.33	06-2058	SQUARE *	0	9,881,277	2.84	(1,710,941)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	57,085,520.56	2,851,422	06-2053	SQUARE *	0	1,900,948	3.33	06-2058	SQUARE *	0	1,620,379	2.84	(280,569)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	59,941.63	2,994	06-2053	SQUARE *	0	1,996	3.33	06-2058	SQUARE *	0	1,701	2.84	(295)
TOTAL NEW SOLAR 2023	*437,731,174.91*	*21,864,672*				*14,576,448*	*3.33*				*12,425,052*	*2.84*	*(2,151,396)*
NEW SOLAR 2024													
341.66 STRUCTURES AND IMPROVEMENTS - SOLAR	34,744,917.36	578,503	06-2054	SQUARE *	0	1,157,006	3.33	06-2059	SQUARE *	0	991,193	2.85	(165,813)
344.66 GENERATORS - SOLAR	372,492,222.44	6,201,996	06-2054	SQUARE *	0	12,403,991	3.33	06-2059	SQUARE *	0	10,626,348	2.85	(1,777,643)
345.66 ACCESSORY ELECTRIC EQUIPMENT - SOLAR	61,083,071.01	1,017,033	06-2054	SQUARE *	0	2,034,066	3.33	06-2059	SQUARE *	0	1,742,560	2.85	(291,506)
346.66 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR	64,139.18	1,068	06-2054	SQUARE *	0	2,136	3.33	06-2059	SQUARE *	0	1,830	2.85	(306)
TOTAL NEW SOLAR 2024	*468,384,349.99*	*7,798,599*				*15,597,199*	*3.33*				*13,361,931*	*2.85*	*(2,235,268)*
348.00 BATTERY STORAGE	24,055,701.49	4,774,534		15-S3	0	1,645,410	6.84		10-S3	0	2,961,777	12.31	1,316,367
TOTAL SOLAR PRODUCTION PLANT	**2,125,236,274.53**	**188,322,573**				**71,875,738**	**3.38**				**62,364,331**	**2.93**	**(9,511,407)**
TOTAL PRODUCTION PLANT	**10,240,352,721.82**	**3,722,112,511**				**465,993,476**	**4.55**				**405,234,323**	**3.96**	**(60,759,153)**
TRANSMISSION PLANT													
350.01 RIGHTS OF WAY	110,259,522.28	27,889,028		75-R3	0	1,341,838	1.22		75-R3	0	1,341,838	1.22 **	-
352.00 STRUCTURES AND IMPROVEMENTS	103,433,228.65	14,790,785		75-R2.5	(15)	1,492,705	1.44		75-R2.5	(15)	1,492,705	1.44 **	-
353.00 STATION EQUIPMENT	2,128,150,435.41	153,886,548		53-R0.5	0	38,603,659	1.81		53-R0.5	0	38,603,659	1.81 **	-
353.01 STATION EQUIPMENT - STEP-UP TRANSFORMERS	109,551,715.37	29,580,705		53-R0.5	0	1,987,217	1.81		53-R0.5	0	1,987,217	1.81 **	-
353.02 STATION EQUIPMENT - MAJOR EQUIPMENT	47,508.58	2,562		53-R0.5	0	862	1.81		53-R0.5	0	862	1.81 **	-
353.91 STATION EQUIPMENT - ENERGY CONTROL	59,549,559.30	17,912,779		17-L2	0	678,203	1.14		17-L2	0	678,203	1.14 **	-
354.00 TOWERS AND FIXTURES	81,443,652.60	62,975,095		65-R3	(25)	1,072,166	1.32		65-R3	(25)	1,072,166	1.32 **	-
355.00 POLES AND FIXTURES	2,530,489,715.02	399,093,054		38-R2	(25)	82,493,965	3.26		38-R2	(25)	82,493,965	3.26 **	-
356.00 OVERHEAD CONDUCTORS AND DEVICES	1,297,216,023.15	127,279,025		55-R1.5	(20)	24,324,309	1.88		55-R1.5	(20)	24,324,309	1.88 **	-
357.00 UNDERGROUND CONDUIT	40,931,204.92	9,381,368		55-R3	0	477,369	1.17		55-R3	0	477,369	1.17 **	-
358.00 UNDERGROUND CONDUCTORS AND DEVICES	87,773,141.49	28,482,007		50-R3	0	1,749,487	1.99		50-R3	0	1,749,487	1.99 **	-
359.00 ROADS AND TRAILS	49,871,005.85	3,765,733		90-R3	0	463,945	0.93		90-R3	0	463,945	0.93 **	-
TOTAL TRANSMISSION PLANT	**6,598,716,712.62**	**875,038,689**				**154,685,725**	**2.34**				**154,685,725**	**2.34**	**-**
DISTRIBUTION PLANT													
360.01 RIGHTS OF WAY	103,578,775.61	2,185,802		75-R3	0	1,427,841	1.38		75-R3	0	1,427,841	1.38 **	-
361.00 STRUCTURES AND IMPROVEMENTS	161,141,281.83	4,730,086		75-R2	(10)	2,289,717	1.42		75-R2	(10)	2,289,717	1.42 **	-
362.00 STATION EQUIPMENT	1,778,499,890.68	116,175,175		60-R0.5	(10)	32,012,998	1.80		60-R0.5	(10)	32,012,998	1.80 **	-
363.00 ENERGY STORAGE EQUIPMENT	78,530,330.00	859,772		n/a	n/a	5,418,593	6.90		10-S3	0	5,418,593	6.90 **	-

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	CURRENT DEPRECIATION RATES: PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROPOSED DEPRECIATION RATES: PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
364.00 POLES, TOWERS AND FIXTURES	1,320,474,987.40	412,919,823		32-R4	(35)	55,523,164	4.20		32-R4	(35)	55,523,164	4.20 **	-
365.00 OVERHEAD CONDUCTORS AND DEVICES	1,593,620,482.23	225,700,032		36-R0.5	(20)	43,511,741	2.73		36-R0.5	(20)	43,511,741	2.73 **	-
365.01 OVERHEAD CONDUCTORS AND DEVICES - CLEARING RIGHTS OF WAY	12,246,452.19	1,620,896		36-R0.5	(20)	334,374	2.73		36-R0.5	(20)	334,374	2.73 **	-
366.00 UNDERGROUND CONDUIT	538,049,416.82	91,973,443		67-R2.5	(5)	8,468,513	1.57		67-R2.5	(5)	8,468,513	1.57 **	-
367.00 UNDERGROUND CONDUCTORS AND DEVICES	1,448,316,375.82	408,291,916		35-R2	(5)	42,754,299	2.95		35-R2	(5)	42,754,299	2.95 **	-
368.00 LINE TRANSFORMERS	1,327,168,859.06	311,264,490		31-R2	(10)	38,355,180	2.89		31-R2	(10)	38,355,180	2.89 **	-
369.01 SERVICES - UNDERGROUND	519,460,084.28	211,109,941		43-R0.5	(5)	11,592,865	2.23		43-R0.5	(5)	11,592,865	2.23 **	-
369.02 SERVICES - OVERHEAD	169,726,707.66	11,893,212		34-R3	(40)	6,872,830	4.05		34-R3	(40)	6,872,830	4.05 **	-
370.00 METERS	23,024,936.68	2,713,870		18-R0.5	(8)	1,374,674	5.97		18-R0.5	(8)	1,374,674	5.97 **	-
370.02 METERS - AMI	393,066,775.95	137,489,229		15-S2.5	0	26,204,452	6.67		15-S2.5	0	26,204,452	6.67 **	-
370.70 EV CHARGERS - DC FAST CHARGERS	4,654,831.43	930,966		10	0	465,483	10.00		10-R2.5	0	465,483	10.00 **	-
371.00 INSTALLATIONS ON CUSTOMERS' PREMISES	13,249,791.02	1,261,914		25-R2	0	481,058	3.63		25-R2	0	481,058	3.63 **	-
371.70 EV CHARGERS - L2 CHARGERS	21,040,680.00	2,151,057		10	0	2,104,068	10.00 ***		7-R2.5	0	2,104,068	10.00 **	-
373.00 STREET LIGHTING AND SIGNAL SYSTEMS	709,306,972.52	193,830,599		25-S0	(10)	30,003,685	4.23		25-S0	(10)	30,003,685	4.23 **	-
TOTAL DISTRIBUTION PLANT	**10,215,157,631.18**	**2,137,102,221**				**309,195,535**	**3.03**				**309,195,535**	**3.03**	**-**
GENERAL PLANT													
390.00 STRUCTURES AND IMPROVEMENTS	423,332,086.45	80,193,964		35-R0.5	(5)	12,572,963	2.97		35-R0.5	(5)	12,266,152	2.90	(306,811)
392.10 PASSENGER CARS	3,097,901.07	2,054,887		9-R3	20	82,094	2.65		9-R3	20	59,723	1.93	(22,371)
392.20 LIGHT TRUCKS	4,363,690.20	1,390,489		9-S3	20	(243,930)	(5.59)		9-S3	20	341,539	7.83	585,469
392.30 HEAVY TRUCKS	26,894,062.38	16,225,972		12-S2	20	1,861,069	6.92		12-S2	20	1,204,847	4.48	(656,222)
392.40 SPECIAL TRUCKS	21,123,427.58	12,317,878		15-L2.5	20	2,836,876	13.43		15-L2.5	20	789,804	3.74	(2,047,072)
392.50 TRAILERS	22,907,475.55	8,630,642		22-S0	0	1,092,687	4.77		22-S0	0	951,155	4.15	(141,532)
396.00 POWER OPERATED EQUIPMENT	20,577,047.69	6,304,397		18-L1.5	5	2,646,208	12.86		18-L1.5	5	1,010,206	4.91	(1,636,002)
TOTAL GENERAL PLANT	**522,295,690.92**	**127,118,227**				**20,847,967**	**3.99**				**16,623,426**	**3.18**	**(4,224,541)**
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT	**17,336,170,034.72**	**3,139,259,137**				**484,729,227**	**2.80**				**480,504,686**	**2.77**	**(4,224,541)**
TOTAL DEPRECIABLE PLANT	**27,576,522,756.54**	**6,861,371,648**				**950,722,703**	**3.45**				**885,739,009**	**3.21**	**(64,983,694)**
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED													
INTANGIBLE PLANT													
302.00 FRANCHISES AND CONSENTS	8,450,028.12	5,693,608											
303.03 MISCELLANEOUS INTANGIBLE PLANT - 3 YR AMORT	5,235,262.42	4,974,488											
303.05 MISCELLANEOUS INTANGIBLE PLANT - 5 YR AMORT	320,137,187.25	279,389,251											
303.10 MISCELLANEOUS INTANGIBLE PLANT - 10 YR AMORT	81,935,349.77	57,724,800											
303.15 MISCELLANEOUS INTANGIBLE PLANT - 15 YR AMORT	90,568,032.29	42,438,693											
TOTAL INTANGIBLE PLANT	**506,325,859.85**	**390,220,840**											
LAND AND LAND RIGHTS													
310.00 STEAM PRODUCTION LAND	4,299,676.74	2,148											
320.00 NON-DEPR LAND AND LAND RIGHTS		(4,605,694)											
340.00 OTHER PRODUCTION LAND	38,839,616.63	(102,244)											
340.66 SOLAR PRODUCTION LAND	19,731.64												
350.00 TRANSMISSION LAND	86,771,423.87	(3,084,398)											
360.00 DISTRIBUTION LAND	57,323,318.88	3,734,974											
389.00 GENERAL LAND	17,450,743.26	(556)											
TOTAL LAND AND LAND RIGHTS	**204,704,511.02**	**(4,055,771)**											
AMORTIZED ACCOUNTS													
312.91 BOILER PLANT EQUIPMENT - 5 YR AMORT	1,712,735.67	685,094											
316.91 MISCELLANEOUS POWER PLANT EQUIPMENT - 5 YR AMORT	1,761,622.12	704,649											
316.92 MISCELLANEOUS POWER PLANT EQUIPMENT - 7 YR AMORT	682,406.52	182,011											
346.01 OTHER PRODUCTION - MISCELLANEOUS COMMUNICATION	3,211.29	3,197											
346.91 MISCELLANEOUS POWER PLANT EQUIPMENT - 5 YR AMORT	123,195.39	49,278											
346.92 MISCELLANEOUS POWER PLANT EQUIPMENT - 7 YR AMORT	45,196.78	12,913											
391.00 OFFICE FURNITURE AND EQUIPMENT	30,829,774.95	26,845,175											
391.01 ELECTRONIC DATA PROCESSING	62,343,390.52	17,496,650											
393.00 STORES EQUIPMENT	8,272,535.37	2,616,747											
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT	110,889,383.54	69,812,295											
395.00 LABORATORY EQUIPMENT	505,775.86	(1,099,853)											
397.00 COMMUNICATION EQUIPMENT	121,471,032.86	61,110,465											
398.00 MISCELLANEOUS EQUIPMENT	8,018,465.00	2,220,043											
398.91 MISCELLANEOUS EQUIPMENT - ENERGYCONT	1,450,800.57	414,929											
TOTAL AMORTIZED ACCOUNTS	**348,109,526.44**	**181,053,594**											

DUKE ENERGY FLORIDA

TABLE 2. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2024
BASED ON CURRENT AND PROPOSED DEPRECIATION RATES

			CURRENT DEPRECIATION RATES					PROPOSED DEPRECIATION RATES					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(7)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(1)	(13)=(11)-(6)
CAPITAL RECOVERY SCHEDULE													
311-316 BARTOW-ANCLOTE PIPELINE		(2,482,673)											
311-316 BARTOW UNITS 1 THROUGH 3		(2,776,448)											
311-316 CRYSTAL RIVER UNITS 1 AND 2		8,773											
311-316 SUWANNEE RIVER UNITS 1 THROUGH 3		(6,058,929)											
341-346 AVON PARK UNITS 1 AND 2		(1,142,744)											
341-346 HIGGINS UNITS 1 THROUGH 4		(431,803)											
341-346 TURNER UNITS 1 THROUGH 4		(5,135,425)											
341-346 RIO PINAR UNIT 1		399,617											
TOTAL CAPITAL RECOVERY SCHEDULE		**(17,619,631.57)**											
TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED	**1,059,139,897.31**	**549,599,031**											
TOTAL ELECTRIC PLANT	**28,635,662,653.85**	**7,410,970,680**											

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.
** DEPRECIATION RATES FOR TRANSMISSION AND DISTRIBUTION ARE THE SAME AS THE CURRENT DEPRECIATION RATES FOR THESE ACCOUNTS.
*** CURRENTLY AUTHORIZED RATE FOR DC FAST CHARGERS

Duke Energy Florida
Retail Separation Factors for 2025-2027
Based on 2024 Settlement Agreement

2024 Settlement Agreement Paragraph 7 states as follows:

7. The separation factors in the 2025 Jurisdictional Separation Study, attached as Exhibit 3, shall remain frozen throughout the Term...

		2025-2027
1.	Production Base Demand	100.000%
2.	Production Intermediate Demand	95.212%
3.	Production Peaking Demand	97.632%
4.	Production Solar Demand	100.000%
5.	Production Base Energy	100.000%
6.	Production Intermediate Energy	93.990%
7.	Production Peaking Energy	97.934%
8.	Production Solar Energy	100.000%
9.	Energy Avg Rate Sales	100.000%
10.	Transmission	70.369%
11.	Distribution Primary	100.000%
12.	Distribution Secondary	100.000%
13.	Distribution Service	100.000%
14.	Distribution Metering	100.000%
15.	Distribution IS Equipment	100.000%
16.	Lighting Facilities	100.000%
17.	Meter Reading	100.000%
18.	Customer Records	100.000%
19.	Customer Billing	100.000%
20.	Labor	97.366%

FPSC EXH NO. 13

ADMITTED

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Duke Energy Florida
Adjustments to DEF's Rate Case
Test Year 2025
Jurisdictional Weighted Average Cost of Capital
($000s)

			Settlement Adjustments							
Line No.	**Class of Capital**	**Notice of Identified Adjustments filed 6/6/24**	**Proration Adjustment**	**ADIT Impacts of Depreciation Expense Adjustments ***	**Pro-Rata Identified Adjustments**	**Jurisdictional Adjusted**	**Ratio**	**Cost Rate**	**Weighted Cost Rate**	*Pretax*
1	Common Equity	$ 9,293,883	$ (7)		$ (297,861)	$ 8,996,015	45.57%	10.30%	4.69%	*6.29%*
2	Long Term Debt	8,288,515	(6)		(265,640)	8,022,869	40.64%	4.49%	1.82%	*1.82%*
3	Short Term Debt	(39,735)	0		1,273	(38,461)	-0.19%	3.25%	-0.01%	*-0.01%*
4	Customer Deposits Active	155,280	(0)		(4,977)	150,303	0.76%	2.61%	0.02%	*0.02%*
5	Customer Deposits Inactive	1,492	(0)		(48)	1,444	0.01%	0.00%	0.00%	*0.00%*
6	Investment Tax Credit	203,664	(0)		(6,527)	197,136	1.00%	7.56%	0.08%	*0.08%*
7	Deferred Income Taxes	2,475,826	14	14,699	(79,348)	2,411,191	12.21%	0.00%	0.00%	*0.00%*
8	**Total**	**$ 20,378,925**	**$ -**	**$ 14,699**	**$ (653,127)**	**$ 19,740,497**	**100.00%**		**6.61%**	*8.20%*
9										
10	**ITC Weighted Cost of Capital:**									
11	Common Equity	$ 9,293,883			$ (297,861)	$ 8,996,015	52.86%	10.30%	5.44%	
12	Long Term Debt	8,288,515			(265,640)	8,022,869	47.14%	4.49%	2.12%	
13	**Total**	**$ 17,582,398**			**$ (563,501)**	**$ 17,018,884**	**100.00%**		**7.56%**	
14										

19 *** ADIT Impacts of Depreciation Expense Adjustments**

20 Calculated by multiplying the rate base impacts on Attachment 2, Page 2 to accumulated depreciation for Adjustments 1, 2, 3, and 6 and the accumulated change in
21 amortization expense for Adjustment 4 and 5 by the statutory income tax rate.

Line No.	Adjustment	Reference	Applicable Book/Tax Diff.	Tax Rate	ADIT
26	Capital Expenditure Reduction	Adjustment 1	3,314	25.345%	840
27	Depreciation Study Adjustments	Adjustment 2	35,737	25.345%	9,058
28	Dismantlement - Remove Accrual Increase	Adjustment 3	6,867	25.345%	1,740
29	Cost of Removal Regulatory Asset - Begin Amortization in 2026	Adjustment 4	9,376	25.345%	2,376
30	Dismantlement Regulatory Asset Deferral	Adjustment 5	1,651	25.345%	418
31	SOBRA - Remove Solar	Adjustment 6	1,051	25.345%	266
32	**Total ADIT Impact**				**$ 14,699**

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DEF's Response to Staff's Third Set of Interrogatories Nos. 11-13

(Including Attachments)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for DeLand West-Dona Vista Transmission Line in Volusia and Lake Counties, by Duke Energy Florida, LLC.	DOCKET NO. 20250078-EI DATED: July 9, 2025

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFFS' THIRD SET OF INTERROGATORIES (NOS. 11-14)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") Third Set of Interrogatories to DEF (Nos. 11-14), as follows:

INTERROGATORIES

11. Refer to DEF's response to Staff's First Interrogatory No. 1(a). Please provide a detailed explanation, cost breakdown and other supporting documentation for the over $30 million allocated to land acquisition and rights. Specifically, identify the locations of the land and easements being obtained.

Response:
The typical right-of-way width to be located within the corridor will range from 100 ft where the route will be cross-country and 55 ft where the route will be adjacent to road right-of-way. New or additional right-of-way is expected to be limited to where DEF's existing transmission lines are located within or adjacent to road right-of-way (ROW), near the Paisley substation and near the Dona Vista substation. The areas where new or additional right-of-way may be needed are where the existing DEF right-of-way is not adequate to accommodate the new DeLand West-Dona Vista transmission line.

The allocation is based on an initial assessment of the proposed corridor, the existing ROW conditions, and the requirements of the proposed 230kV/69kV double-circuit structures. These estimates were developed from early-stage engineering and ROW planning. The review considers the impacts throughout the 26.5 miles and the 240 property owners in the corridor.
Efforts are being made to minimize impacts to private landowners and limit new acquisitions wherever feasible by utilizing existing corridors and optimizing structure placement within allowable limits.
The estimated $30 million cost includes:
- Easement and land rights acquisition: based on current market values, property type, and extent of rights required
- Surveying and appraisal services
- Title searches and legal fees

- Negotiation and acquisition support services
- Asset Protection services and removal of mandatory encroachments

Below is a breakdown of the Easement and Encroachments Impacts identified:
- A portion of the existing structures are located within or adjacent to road ROW. Proposed double circuit structures and increased clearance requirements could trigger the need for additional or new easement rights, which are necessary to maintain compliance.
- Some areas in the existing DEF ROW are narrow, or not adequate to accommodate the new proposed double circuit. In these areas, additional or new easements might be required.
- Supplementals might be required in existing easements rights to incorporate the proposed double-circuit configuration, which in many cases is not part of our existing easements rights triggering the requirement for supplemental easements.
- Removal of encroachments. In older transmission corridors like this one, permanent structures by third parties and landowners may not meet current safety or clearance standards, interfering with the safe operation of the transmission line (signs, billboards, sheds, etc.).

12. Refer to DEF's response to Staff's First Interrogatory No. 5(b) and witness Rahman Direct Testimony page 15, lines 12 through 17. Please reconcile the significant difference between the $73.4 million for rebuilding the 69kV circuit stated in the interrogatory response and the $13.8 million presented in the direct testimony. As part of your response, specify if new transmission structures are necessary for this rebuild and if so, why?

Response:
The discrepancy between the $73.4 million cited in DEF's response to Staff's First Interrogatory No. 5(b) and the $13.8 million referenced in witness Rahman's Direct Testimony arises from the scope and context in which each estimate was developed. The $13.8 million represents the added cost of the 69kV rebuild when included as part of the larger 230kV transmission project. This amount covers the scope specific to the 69kV rebuild, excluding shared efforts and infrastructures such as poles and foundations, that are already required for the new 230kV line.

The $73.4 million reflects the full standalone cost of rebuilding the 69kV line as an independent project, assuming it is not bundled with the 230kV line. This estimate includes all associated infrastructure, mobilization, permitting, and overheads that would otherwise be shared with the larger 230kV transmission project. New transmission structures are necessary for the 69kV rebuild due to the increased conductor size and associated mechanical loading by the conductor upgrade to 1272 ACSS, which supports future load growth.

13. Refer to DEF’s response to Staff’s First Interrogatory No. 3. Please provide a detailed breakdown of the future projected number of single and/or double contingency events expected to impact customers in DEF's service area within Lake, Volusia, Seminole, and Orange counties from 2025 through 2031. For each projected event, specify the anticipated year, the number of customers expected to be affected, and the estimated capacity loss.

Response:

The primary driver for the Project is the double contingency loss of the Central Florida to Haines Creek 230 kV line and the Piedmont to Welch Road 230 kV line. The reliability concern is based on the risk of contingency events rather than probability. Specifically, if this double contingency event were to occur today, an estimated 29,000 customers would be unserved for an extended period (until restoration of at least one of the 230 kV lines) due to the activation of the Lake County UVLS scheme. This scheme is set to trip specified feeders at four substations, and as such the number of customers and their associated load could vary slightly (i.e., increase) per year through 2030.

[redacted]

[redacted]

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AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 3rd day of July, 2025, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared DAVE RAHMAN, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 11-13 from Staff's Third Set of Interrogatories to Duke Energy Florida, LLC (NOS. 11-14) in Docket No(s). 20250078-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of July, 2025.

Dave Rahman

CHANELLE L. GARDNER
Commission # HH 464855
Expires November 15, 2027

Notary Public
State of Florida, at Large

My Commission Expires:

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 8th day of July, 2025, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MARCIA OLIVIER, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number(s) 14 from Staff's Third Set of Interrogatories to Duke Energy Florida, LLC (NOS. 11-14) in Docket No(s). 20250078-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of July, 2025.

Marcia Olivier
Marcia Olivier

Sandra Cope
Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
SANDRA COPE
MY COMMISSION # HH 214522
EXPIRES: March 8, 2026

FILED 7/17/2025
DOCUMENT NO. 06374-2025
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for DeLand West-Dona Vista Transmission Line in Volusia and Lake Counties, by Duke Energy Florida, LLC.	DOCKET NO. 20250078-EI DATED: July 17, 2025

DUKE ENERGY FLORIDA, LLC'S NOTICE OF FILING PROPOSED STIPULATIONS

Duke Energy Florida, LLC ("DEF"), by and through its undersigned counsel, hereby submits the following proposed stipulations to the Florida Public Service Commission for approval. Commission approval of these stipulations will fully resolve all issues in this docket.

DEF and staff have proposed stipulations on the issues set out below.

ISSUE 1: Is there a need for Duke Energy Florida, LLC's proposed DeLand West - Dona Vista 230 kV transmission line, taking into account the need for electric system reliability and integrity, as prescribed in Section 403.537, Florida Statutes?

Yes. As evidenced in the record, DEF has demonstrated that if it does not add transmission capacity in the projected service area there are sufficient transmission risks that would result in power outages in the event of a double contingency event in Lake, Volusia, Seminole, and Orange Counties. While DEF has implemented an Under Voltage Load Shedding (UVLS) scheme to prevent a larger, more catastrophic collapse of the larger electric grid, the customers in the area would experience extended outages. If a double contingency event occurred today, the record indicates that an estimated 29,000 customers would experience extended power outages due to the UVLS activation. Over the next 10 years, DEF demonstrated that the Dona Vista areas' load will grow by an average of 25%, which would further exacerbate this issue.

The record further supports the necessity for this 230 kV transmission line based on its

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ability to: (a) improve the reliability of service for DEF customers connected to the existing 230 kV circuits in Lake, Volusia, Seminole, and Orange Counties; (b) increase north-to-south power transfer capabilities, providing an additional transmission path and optimizing power flow distribution within Volusia and North Orlando areas; (c) mitigate potential overloads and address low voltage conditions during system contingencies; and (d) decrease the loading on existing transmission circuits. Therefore, DEF has demonstrated a need for the proposed DeLand West to Dona Vista 230 kV transmission line project, taking into account the need for electric system reliability and integrity.

ISSUE 2: Is there a need for Duke Energy Florida, LLC's proposed DeLand West -Dona Vista 230 kV transmission line, taking into account the need for abundant, low cost electrical energy to assure the economic well-being of the citizens of the State, as prescribed in Section 403.537, Florida Statutes?

Yes. DEF has demonstrated that the selected project is the most cost-effective and efficient alternative that provides improved reliability for customers served in DEF's service area. Therefore, the proposed DeLand West to Dona Vista 230 kV Transmission Line is needed, taking into account the need for abundant, low-cost electrical energy to assure the economic well-being of the residents of the state.

The approximate cost of the selected project, with its starting and ending points at DeLand West Substation and the Dona Vista Substation, respectively, has a projected in-service cost of $165 million. As supported by the record, these starting and ending points would enable the new transmission line to stay primarily within the existing corridor, potentially reducing the need for new easements. DEF considered four alternative transmission projects which were subsequently rejected for various reasons such as costs or siting concerns.

ISSUE 3: Are Duke Energy Florida, LLC's DeLand West Substation in Volusia County and its Dona Vista Substation in Lake County the appropriate starting and ending points for the proposed DeLand West - Dona Vista 230 kV transmission line?

Yes. DEF has demonstrated that a new transmission line sited from DEF's existing DeLand West Substation in Volusia County to DEF's existing Dona Vista Substation in Lake County would be the most reliable, cost-effective means to serve the existing and projected load growth within the area. The record demonstrates that these starting and ending points would enable the new transmission line to stay primarily within the existing corridor, potentially reducing the need for new easements. Therefore, the appropriate starting and ending points are the DeLand West Substation and the Dona Vista Substation, respectively. The proposed transmission line's corridor would be approved under the Transmission Line Siting Act (TLSA), with final approval resting with the Transmission Line Siting Board or, if undisputed, the Florida Department of Environmental Protection (FDEP).

ISSUE 4: Should the Commission grant Duke Energy Florida, LLC's petition for determination of need for the proposed DeLand West - Dona Vista 230 kV transmission line project?

Yes. DEF has demonstrated that the DeLand West to Dona Vista 230 kV Transmission Line Project is needed taking into account the need for system reliability and integrity and the need for the delivery of abundant, low-cost electrical energy to retail customers. The appropriate starting and ending points of the line are the existing DeLand West Substation in Volusia County and the Dona Vista Substation in Lake County. The corridor within which the proposed 230 kV transmission line will be sited will be determined under the TLSA, with final approval resting with the Transmission Line Siting Board or, if undisputed, the FDEP.

ISSUE 5: Should this docket be closed?

Yes. This docket should be closed after the time for filing an appeal has run.

DEF and staff further propose that the Comprehensive Exhibit List and all exhibits be included in the record. DEF respectfully requests that the Commission approve these proposed stipulations.

Respectfully submitted this 17th day of July, 2025.

/s/ Dianne M. Triplett
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FLRegulatory@Duke-Energy.com

Attorneys for Duke Energy Florida, LLC

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Electronic Mail to the following on the 17th day of July, 2025:

/s/ Dianne M. Triplett
Attorney

Adria Harper / Jennifer Augspurger Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 aharper@psc.state.fl.us jaugspur@psc.state.fl.us	