CONFIDENTIAL

FRIO COUNTY LINE UPGRADES

ECONOMIC BENEFIT ANALYSIS

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EXECUTIVE SUMMARY

LCG Consulting (LCG) was commissioned by 7X Energy to assess the economic benefits of proposed Frio County upgrades to the ERCOT system. As of November 1, 2019, about 580 MW of solar capacity has executed interconnection agreements (SGIA) in Frio county at the 138 kV Paloduro substation (5866) and 138 kV Pearsall Switching Station (5895) with planned in-service dates in May & December 2021. Current transmission system in this region is not capable of handling this level of additional generation and results in several local line overloads.

The proposed upgrades, called Frio County upgrades, listed below are expected to improve transfer capability in the region with increased generation.

1. Moore – Bigfoot 138 kV Line upgrade (Phase 1)
2. Dilley Switch 138/ 69 kV Transformer upgrade (Phase 1)
3. Moore – Hondo Creek 138 kV Line upgrade (Phase 2)

LCG, using its proprietary UPLAN software, has performed production cost simulations for study year 2022 to evaluate the savings to ERCOT-wide production cost as a result of this transmission upgrade. LCG performed this analysis with the goal of using methods and practice aligned with ERCOT methodology for performing an economic transmission evaluation. Based on LCG's analysis the Phase 1 upgrades result in $1.8M of annual savings and Phase 1 & 2 together result in $3.2M of annual savings in ERCOT production cost. Based on the revenue requirements outlined in ERCOT Protocol Section 3.11.2 (5), economic planning criteria, in order for Phase 1 upgrades to meet the economic the total cost of the upgrades (#1 & #2) should not exceed $13M and the total cost of all upgrades should not exceed $23M.

1. INTRODUCTION

As of October 2019, 7X Energy's 178 MW Elara Solar (#21INR0287) and First Solar's 205 MW Horizon Solar (#21INR0261) units meet ERCOT planning guide section 6.9 requirements with Signed Interconnection Agreement (SGIA) and Financial Security and Notice to Proceed Provided. Elara and Horizon solar units have planned in-service dates of April 1, 2021 and December 31, 2021 respectively. Preliminary analysis indicated that increase in local generation causes overload on nearby lines under contingency conditions. Major overloaded elements were STEC's Moore – Bigfoot 138 kV and Moore – Hondo Creek 138 kV line, AEP's Dilley Switch 138/69 kV transformer. Figure 1-1 shows the location of new unit additions and the resulting overloaded lines as modeled in UPLAN.

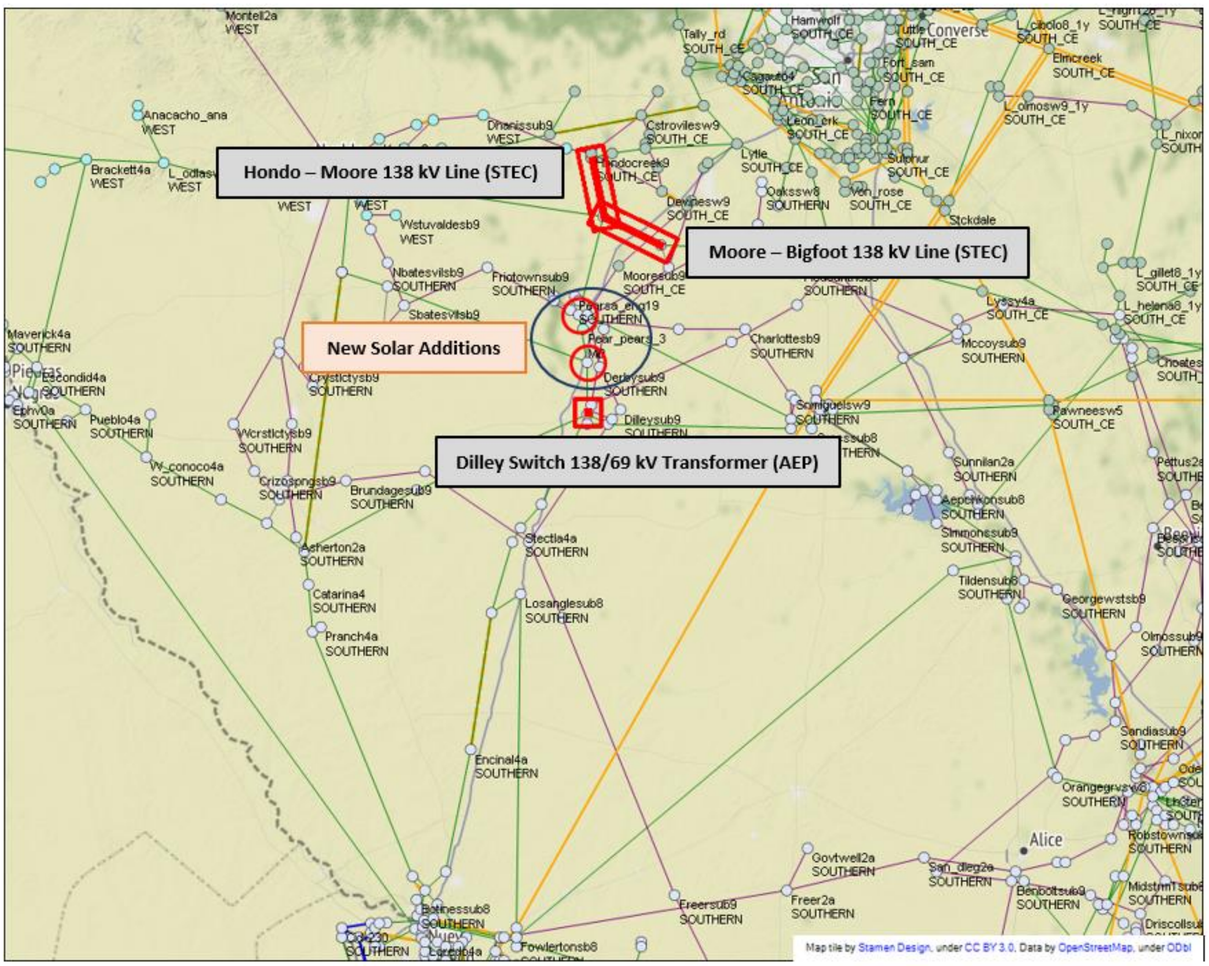

Figure 1-1 Frio county new solar additions & resulting overloads

The objective of this study is to evaluate the production cost benefit of the proposed Frio county line upgrades and to identify changes in local and ERCOT-wide congestion patterns, if any. LCG has performed a production cost simulation using its proprietary UPLAN software to evaluate the savings to the ERCOT system. This report summarizes the modeling methodology, input assumptions, and results of hourly nodal network simulations of the ERCOT system for the year 2022.

2. MODELING TOOL OVERVIEW

For this analysis, LCG's proprietary UPLAN Network Power Model (UPLAN-NPM) and PLATO-ERCOT data model was utilized for the nodal market simulation. UPLAN simulates a balanced system with hourly forward-looking unit commitment, hourly and sub-hourly economic dispatch, and optimal power flow. This model provides a rich, integrated representation of physical features of the electric generators, loads and transmission, financial characteristics, and system operation specific to the ERCOT system. UPLAN simulations provide a realistic projection of the physical and financial operations of all the modeled regions. Such realistic projection is useful for assessing the engineering, economic, and financial implications of spatial as well as temporal changes in operations, reliability, production costs, and resources.

The model performs marginal cost or bid based energy and ancillary service procurement, congestion management, as well as complete contingency analysis with Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED).[1]

3. STUDY ASSUMPTIONS

Because the new solar units in Frio County are expected to start operation on the second half of 2021, year 2022 was considered to be a more appropriate year for the study. LCG used 2019 RTP Economic Study Case Assumptions as a start and modified the assumptions to appropriately represent 2022. This section provides an overview of the key inputs used and the changes made to create the study case.

3.3 Demand

[1] http://www.energyonline.com/Products/Uplane.aspx
http://www.energyonline.com/Products/Plato.aspx

Annual Peak (MW) and Energy (GWh) forecasts used in the study are presented in Table 3-1 below.

Table 3-1 Annual peak (MW) load forecast by weather zones

Weather Zone	Annual Peak (MW)	Annual Energy (GWh)
Coast	17,529	96,582
East	2,523	12,786
Far West	1,909	10,376
North	1,821	8,957
North Central	25,573	123,106
South Central	12,427	61,245
Southern	5,242	29,074
West	1,845	10,201
Flat	17,400	152,424

Hourly load shapes for the eight weather zones were derived and modified from *"2019RTP_ERCOT_load_forecast_2020_to_2025_by_historical_year2013"* published April, 2019. 2013 historical year shapes were shifted to 2022 in order to align the weekends/ weekdays. Analysis of the data further showed that for some weather zones, the annual peaks were lower than recent ERCOT 50-50 projections. Therefore, monthly peak MW's were modified based on Long-Term Daily Load Forecast, published September 2019.

3.4 Generation

LCG's ERCOT generation data model includes all existing units included in ERCOT Capacity, Demand & Resources (CDR) report, published May 2019 and planned additions based on GIS report, published September 2019. All units from the interconnection queue that have a) Signed Interconnection Agreement, b) Provided sufficient financial security to the TSP and Notice to Proceed provided and c) with commercial online date before 1/1/2023 were included.

Table 3-2 provides the list of renewable additions modeled in the South.

Table 3-2 Renewable generators included in South Zone

GINR Reference Number	Project Name	County	Projected COD	Fuel	Capacity (MW)
14INR0045	Torrecillas Wind	Webb	10/17/2019	Wind	301
19INR0053	Hidalgo II Wind	Hidalgo	11/15/2019	Wind	51
16INR0081	Mesteno Windpower	Starr	3/1/2020	Wind	202
19INR0073	Shakes Solar	Zavala	6/24/2020	Solar	206
18INR0016	RTS 2 Wind	McCulloch	7/10/2020	Wind	180
17INR0025	Reloj Del Sol Wind	Zapata	10/31/2020	Wind	202
16INR0111	Las Lomas Wind	Starr	12/1/2020	Wind	200
21INR0276	Elara Solar	Frio	4/1/2021	Solar	178
21INR0261	Horizon Solar	Frio	12/31/2021	Solar	204

Heat rate curves, operating costs and other characteristics of thermal units are based on LCG's PLATO data model developed using ERCOT market data and Energy Information Administration (EIA) publications, among other sources. Planned and Forced outages on generating units are based on UPLAN outage scheduler.

Unit retirements and mothball status is based on ERCOT Approved and Announced retirements and 2019 RTP Economic Case assumptions. A list of retired/mothballed units excluded from the study is provided in Table 3-3 below.

Table 3-3 Retired/ Mothballed Units excluded from the study

Unit Name	Capacity (MW)	Zone	Fuel	Retirement/ Mothball Date
Monticello 1	580	North	Coal	1/3/2018
Monticello 2	580	North	Coal	1/3/2018
Monticello 3	795	North	Coal	1/3/2018
Sandow 4	600	South	Coal	1/10/2018
Sandow 5	600	South	Coal	1/10/2018
Big Brown 1	606	North	Coal	2/11/2018
Big Brown 2	602	North	Coal	2/11/2018
J T Deely 1	420	South	Coal	12/31/2018
J T Deely 2	420	South	Coal	12/31/2018
Gibbons Creek 1	470	North	Coal	6/1/2019
West Texas Wind Energy	75	West	Wind	11/15/2019
Oklaunion 1	667	West	Coal	10/31/2020
Decker Creek 1	320	South	Gas	12/31/2020
Decker Creek 2	428	South	Gas	12/31/2021

3.4.1 Renewable Generators

2013 weather year hourly wind profiles for existing units were used from "ERCOT Wind Patterns for Existing Sites, 1980-2017" file published, September 2018. County specific profiles from *"ERCOT 2005-2013 Onshore Wind Generation Profiles"* file published, February 2017 was used for all future wind units. Similarly, 2013 weather year profiles were used for all solar units based on *"ERCOT SolarProfiles 1997-2015 CentralStation Existing 20161106"* file published, February 2017. Monthly capacity factors of hydro units were developed and used based on three-year average (2016-2018) historical generation.

Wind and solar generators were dispatched based on $0/MWh offer.

3.4.2 DC Ties & Switchable Generators

Dispatch of DC Ties with SPP (DC_E & DC_N) and CFE (DC_L, DC_R and DC_S) were modeled based on assumptions from *"20190610.Addendum_B_2019_RTP_Economic_Input_Assumptions.xlsx"* published, June 2019. Based on the RTP case assumptions, both ties with SPP were modeled as import ties and it was represented using pseudo-generators. For the study, these generating units were modeled with characteristics similar to a combined cycle unit.

Switchable generators unavailable to ERCOT in summer (June – September) were also modeled based on assumptions from the same file.

3.4.3 Fuel Price Forecast

Monthly natural gas prices forecast for 2022 is also based on 2019 RTP Economic Case assumptions and displayed in Figure 3-1 below. Coal price forecasts used in the study are based on the mine mouth prices and transportation rates from the 2019 EIA Annual Energy Outlook published March 2019.

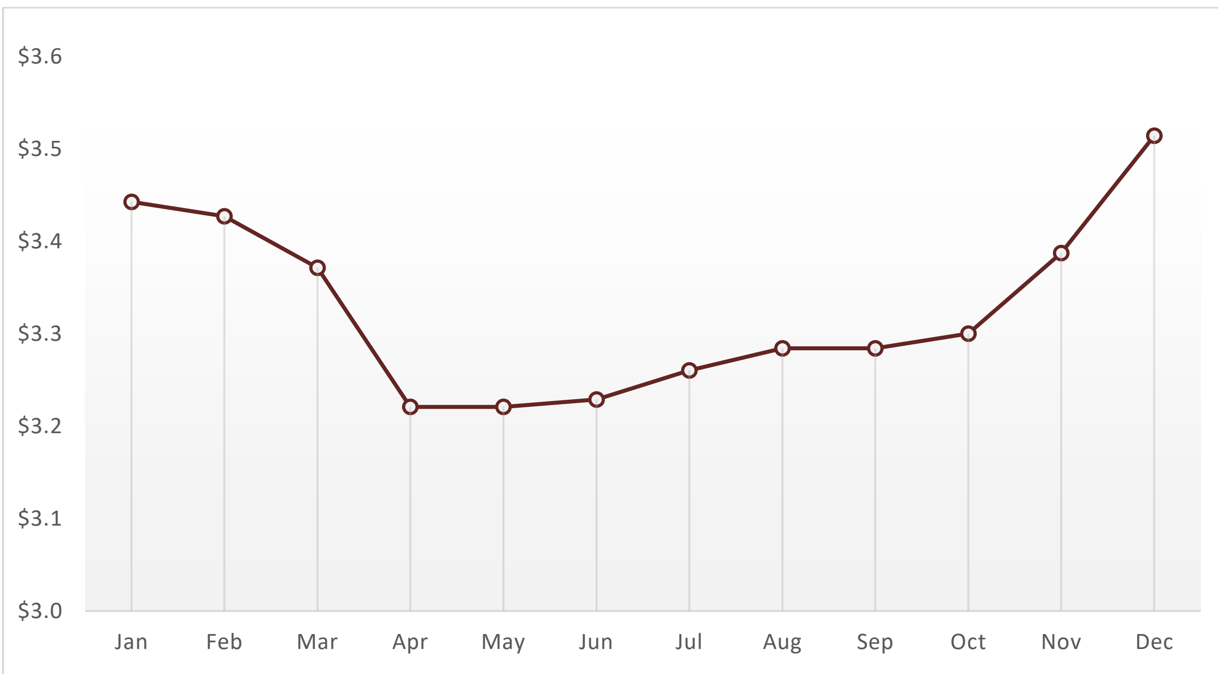

Figure 3-1 Monthly ERCOT-Wide Natural Gas Price Forecast (Nominal $/MMBtu) – 2022

3.4.4 Reserve Requirements

Reserve requirements used in the study case was based on ERCOT Projected Ancillary Service Requirements, published September 2019 varies by month and hour. For Responsive Reserve Services (RRS), only contribution from generating resources (50% of the total requirement) was modeled and load resources contributing to RRS was not modeled. Average Ancillary Service (A/S) requirements in the study case is:

- Regulation Up – 310 MW
- Regulation Down – 289 MW
- RRS (Generators) – 1,354 MW
- Non-Spin – 1,518 MW

3.5 Transmission

The starting point for transmission topology used in the study was the 2019 RTP Eco Study Start Case Input file for 2021 published, September 2019. The topology was extended to 2022 by adding planned transmission upgrades with expected COD before December 2022, based on "ERCOT_June_TPIT_No_Cost_060119.xlsx". Modified study case is expected to contain all operating and planned projects until 2022.

3.5.1 Base Case Modifications

List of all projects added to the 2021 RTP base case is provided in the Appendix - Table A-1. In general, following transmission projects were included.

- Tier 1 or 2 projects in load zones
- Tier 3 or 4 projects in South load zone

Ratings and characteristics of the line upgrades/modifications are provided in Appendix - Table A-2 and new load serving substations and their corresponding load MW's are provided in Appendix - Table A-3.

Contingencies and their definitions modeled in the study case were from the 2019 RTP Eco Study Start Case Input file for 2021 published, September 2019.

At the time of the study, there were no transmission outages planned for the study period and therefore were not modeled.

Generic Transmission Constraint (GTC) limits were modeled for the Panhandle (PNHNDL), Rio Grande Valley Import (VALIMP)and North Edinburg to Lobo (NE_LOB) GTC's. While there are several other GTCs used in the ERCOT market currently, most issues are expected to be resolved with upgrades in place before the study year 2022. Limits on these three GTCs are based on 2019 RTP Economic Case published, September 2019 with the exception of PNHNDL. The September RTP case had a limit of 9,999 MW while all previously published cases limited it at 4,293 MW which was assumed appropriate and implemented in the study as well.

3.5.2 Frio County Upgrade Details

Overloads in the region were observed on lines owned by STEC and AEP. Therefore, the proposed upgrades are grouped based on ownership. Phase 1 includes the Moore to Bigfoot 138kV Line, and the Dilley Switch 138/69kV transformer owned by AEP and Phase 2 includes the Moore to Hondo Creek 138kV line owned by STEC. However, all these upgrades will be needed by end of year 2021.

3.5.2.1 Phase 1 Upgrades (AEP)

In the upgrade cases, AEP's Moore – Bigfoot 138 kV line which is currently rated 122/ 122 MVA is increased to 382/ 382 MVA and Dilley Switch 138/69 kV transformer which is currently rated at 38/41 MVA is increased to 130/ 130 MVA. Table 3-4 below gives the characteristics of the upgraded elements.

Table 3-4 AEP Upgrade Characteristics

Upgraded Element	Resistance (pu)	Reactance (pu)	Admittance (pu)	Service Voltage (kV)	Line Mileage (mi)	Cap A/ Cap B (MVA)
Moore – Bigfoot Line	0.00254	0.02116	0.0057	138	6.1	382/ 382
Dilley Switch Transformer	0.00197	0.00743	0.0000	138/ 69	-	130/ 130

3.5.2.2 Phase 2 Upgrades (STEC)

Phase 2 upgrade recognizes the Moore – Hondo Creek 138 kV line that is currently rated at 114/ 127 MVA and is considered to be upgraded to 285/ 285 MVA. Characteristics of this line modeled in the upgrade case is presented in Table 3-5.

Table 3-5 STEC Upgrade Characteristics

Upgraded Element	Resistance (pu)	Reactance (pu)	Admittance (pu)	Service Voltage (kV)	Line Mileage (mi)	Cap A/ Cap B (MVA)
Moore – Hondo Creek Line	0.00552	0.05061	0.0156	138	13.5	285/ 285

4. RESULTS OF THE ECONOMIC ANALYSIS

Production cost simulations were performed for 2022 with and without the proposed upgrades. Local and ERCOT-wide congestion patterns and overall production cost to the system were compared between the two cases and discussed in this section.

4.3 Congestion

4.3.1 Local Congestion

Figure 4-1 shows the overloaded elements in the local region due to solar generators added in Frio County.

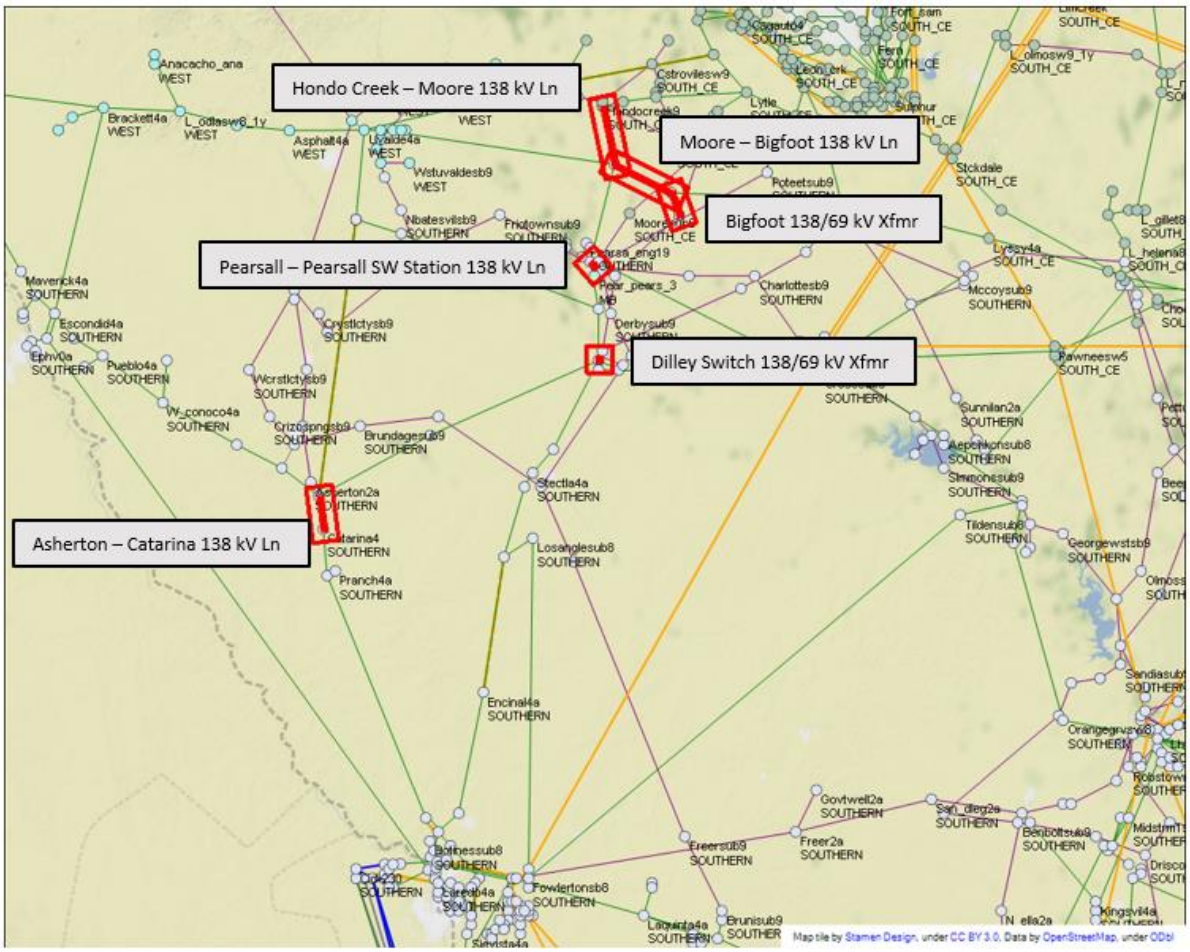

Figure 4-1 Base Case overloads due to Increase in Frio County Solar Generation

Congestion on these lines under different scenarios can be seen in Table 4-1 below. Congestion Rent ($) for these lines are color coded with Red indicating rent > $5M, Orange indicating rent between $500K and $5M and Yellow indicating rent < $500K.

Table 4-1 Congestion comparison between scenarios

Overloaded Element	% of Time Overloaded			Congestion Rent ($)		
	Base Case	Phase 1	Phase 1 & 2	Base Case	Phase 1	Phase 1 & 2
Moore – Bigfoot 138 kV Ln L/O: Hondo Creek to Moore 138 kV Ln	13.05%	-	-			
Hondo Creek – Moore 138 kV Ln L/O: Moore – Bigfoot 138 kV Ln	0.05%	9.28%	-			
Dilley Switch 138/ 69 kV Xfmr L/O: Dilley Switch AEP to Hindes Tap 138 kV Ln & Dilley Switch AEP to Jardin 138 kV Ln	8.23%	-	-			
Moore – Bigfoot 138 kV Ln L/O: Dilley Sub to Derby Sub 69 kV Ln & Dilley Switch AEP to Palo Duro 138 kV Ln	1.35%	-	-			
Bigfoot 138/ 69 kV Xfmr L/O: Hondo Creek to Moore 138 kV Ln	0.02%	0.35%	2.55%			
Pearsall – Pearsall SW 138 kV Ln L/O: Pearsall to Moore 138 kV Ln	0.08%	0.07%	0.02%			
Hondo Creek – Moore 138 kV Ln L/O: Elm Creek to San Miguel 345 kV Dbl Ckt Ln	0.23%	0.46%	-			
Asherton – Catarina 138 kV Ln L/O: Fowlerton to San Miguel 345 kV Ln & Fowlerton to Lobo 345 kV Ln	7.09%	6.48%	6.37%			
Asherton – Catarina 138 kV Ln L/O: Lobo to Cenizo 345 kV Ln	7.66%	6.15%	4.25%			
Asherton – Catarina 138 kV Ln L/O: Dilley Switch AEP to Hindes Tap 138 kV Ln & Dilley Switch AEP to Jardin 138 kV Ln	3.53%	2.39%	2.23%			

4.3.2 ERCOT- Wide Congestion

Top 10 constraints in the ERCOT system observed in Base and upgrade cases are listed in Table 4-2. Congestion Rent ($) calculated as the product of line capacity (Rating A if thermal and Rating B if contingency overload) and Shadow Price ($/MW)[2], for all the reported constrains are > $5,000,000 in all

[2] Shadow Price ($/MW) is defined as the system savings that would occur if the capacity of a transmission line were to be increased by a single MW.

cases. Percentage of the time in a year that these lines were overloaded also remained unchanged in base and upgrade cases.

Table 4-2 Top 10 ERCOT-Wide constraints

Overloaded Element	Worst Contingency	Rating (Cap A/ Cap B)	% of Time Congested
Panhandle GTC	BaseCase	4,273	25%
Kendall – Bergheim 345 kV Ln	Cagnon to Kendall 345 kV Ln & Cico to Comfort 138 kV Ln	1,086	21%
West TNP – TI TNP 138 kV Ln	Lewisville to Jones Street 138 kV Ln	190	11%
JK Creek – Twin Oak 345 kV Ln	Singleton to Jewett 345 kV Dbl Ckt Ln	1,287	34%
Wichita Falls – Henrietta West 69 kV Ln	Birdwell to Loftin 69 kV Ln	43	12%
Ballinger 138/ 69 kV Xfmr	Cedar Gap TEC to Abeline South 69 kV Ln & Sawgrass to Abeline South 69 kV Ln	69	16%
Lanham Tap – Henrietta West 69 kV Ln	Birdwell to Loftin 69 kV Ln	46	4%
North Edinburg – Lobo GTC	BaseCase	1,638	11%
Brookhollow AEP – Port Lavaca 69 kV Ln	Blessing 138/ 69 kV Xfmr	44	9%
Long Draw – Farmland 345 kV LN	Cottonwood to Whiteriver 345 kV Dbl Ckt Ln	1,084	9%

4.4 Production Cost Savings

LCG's simulation results with and without the upgrades showed significant production cost savings to the ERCOT system due to Phase 1 and combined Phase 1 & 2 upgrades and reported in Table 4-3 below.

Table 4-3 Annual Production Cost Savings

Scenario	Annual Production Cost Savings
AEP Owned Transmission Upgrades (Phase 1)	$1.84 M
AEP & STEC Owned Transmission Upgrades (Phase 1 & 2)	$ 3.21 M

5. CONCLUSION

Based on the economic planning criteria outlined in the Protocol Section 3.11.2 (5), the first-year annual revenue requirement for a project to be economic is assumed to be 14% of the total cost. LCG's production cost simulations for the year 2022 shows that Phase 1 upgrades (AEP Scope) can meet the economic criteria if the total cost of upgrades does not exceed $13M. The combined Phase 1 & 2 (AEP and STEC scope together) can meet the economic criteria if the total cost of all upgrades does not exceed $23M.

A. APPENDIX *(Contents removed intentionally)*

Table A-1 TPIT Projects added to 2021 RTP BaseCase

Table A-2 Characteristics of line upgrades made to the base case

Table A-3 New load bus additions to the base case