LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 161

Responding Witness: Daniel K. Arbough

Q-161. Provide any internal investment proposals prepared for projects included in rate base or CWIP in the past two years.

A-161. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Investment Proposal for Investment Committee Meeting on: February 27, 2020

Project Name: Ohio Falls Masonry and Trash Rack Upgrades

Total Capital Expenditures: $14,300k (Including $2,000k of contingency)

Project Number(s): 160416

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John S. Williams

Description of Project

This proposal seeks approval for masonry repairs and window replacement of the Ohio Falls Generating Station's (Station) multi-unit powerblock exterior as well as repairs to the Station's trash rack guides under the Ohio Falls Masonry and Trash Rack Upgrades project.

An effort began in 2004 to upgrade and refurbish the Station's eight hydroelectric units which had not seen a major overhaul since originally placed into service in the mid-1920s. That effort, in general terms, included major electrical/controls and mechanical upgrades which were completed in 2018 at an overall project spend of approximately $145M. That upgrade did not address the deterioration of the Station powerblock's exterior concrete façade masonry or windows, nor did it address the deteriorated trash rack guide system (which protects the hydroelectric units' intake(s) from river debris).

This proposal will fund three major contracts: (1) powerblock façade masonry; (2) window replacement; and (3) trash rack guide repairs. The contracts will be separate, due in large part to the specialty nature of façade work on the powerblock and the underwater repair work of the trash rack guides. The window replacement scope was added to this proposal subsequent to the powerblock façade masonry bidding period; there is potential the successful façade bidder may also win the window replacement.

Why is the project needed?

As captured in an annual FERC Dam Safety Inspection report, the exterior concrete of the powerblock is seeing cracking and experiencing spalling. Rebar is exposed in a multitude of locations across all four sides of the building. [redacted] was contracted to perform a survey of the entire building façade and engineer repairs to the deteriorated sections. Without repairs, the deteriorated sections will expand to damage adjacent, competent concrete, requiring a more extensive repair in the future. Also without repairs, the spalling will continue, allowing variously sized concrete sections to fall off the powerblock. The repairs generally consist of saw-cutting the deteriorated sections to an extent encountering competent concrete, cleaning or replacing rebar, and installing backfill concrete. In addition, the windows and window frames of the powerblock are deteriorating; periodically, windows free themselves of the failing frames and fall. Aside from the overhead debris hazard, this allows greater access for birds and insect infestation. The window replacement portion of this project was previously budgeted by the Station, but scheduled to occur in 2026. This window replacement work (and budget) has been accelerated to coincide with the concrete façade repair work, as significant concrete repairs are required at the window frame locations.

The upstream and northern side of the powerblock's façade repairs will occur in the 2020 construction season and the downstream and southern side repairs will occur in the 2021 construction season.

The trash rack guides, which protect the unit intakes from receiving river debris on all eight units, have become damaged by river debris impacts and freeze-thaw cycles over time. Visible rotation of the headworks' anchors exist, and as evidenced from a recent underwater dive inspection, the riverbed rock sockets are deteriorating. [redacted] was contracted to engineer repairs and improvements to the trash rack guides. Without the repairs/improvements, the trash rack guides will continue to deteriorate, ultimately allowing the racks to become free of the guide systems. The repairs generally consist of re-establishing a competent connection between the headworks' top-of-steel guides to existing concrete and the underwater installation of new steel beam supports, both of which are required across eight units.

The trash rack guide repairs will occur in the 2020 construction season.

Support contracts are required and captured in the proposal: (1) asbestos containing material is present in the window putty and frame caulk which must be abated to install the concrete repairs as well as the window replacement; (2) third party quality control and owner's engineer services are included in the project; and (3) there is potential river dredging required to access the trash rack guide repair locations.

The aforementioned support contracts and Project Engineering overheads will span the project duration (Q1 2020 through Q4 2021).

Budget Comparison & Financial Summary

Table 1 below details capital investment, by year:

Table 1

Capital ($000)	Pre-2020	2020	2021	Post 2021	Total
Subprojects					
Concrete Façade Repairs	$0	$2,600	$4,300	$0	$6,900
Trash Rack Repairs	$0	$1,500	$0	$0	$1,500
Façade Repairs Quality Control	$0	$180	$180	$0	$360
Trash Rack Owner's Engineer (Design)	$20	$50	$0	$0	$70
Dredging	$280	$0	$160	$0	$440
Trash Rack Quality Control	$0	$70	$0	$0	$70
Asbestos Abatement	$0	$100	$200	$0	$300
Window Replacement	$0	$0	$2,000	$0	$2,000
Subtotal	$300	$4,500	$6,840	$0	$11,640
Overheads & Contingency					
Overheads	$0	$300	$360	$0	$660
Project Contingency	$0	$0	$2,000	$0	$2,000
Subtotal	**$0**	**$300**	**$2,360**	**$0**	**$2,660**
Project Total	**$300**	**$4,800**	**$9,200**	**$0**	**$14,300**

This proposal incorporates actual bid data, vendor and Owner's Engineer estimates, and LG&E estimates based upon historical costs, as described below:

- The concrete façade repair value reflects recent bid data.
- The trash rack repair value reflects a vendor estimate.
- The window replacement value reflects a vendor estimate.
- The asbestos abatement value reflects an Owner's Engineer estimate.
- Quality Control values are based upon Owner's Engineer estimates.
- River dredging value is based upon historical costs.
- Project Engineering overheads are based upon historical values at Ohio Falls.

Table 2 below summarizes the project capital investment compared to the 2020 BP, by year:

Table 2

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	300	4,800	9,200	-	14,300
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	300	4,800	9,200	-	14,300
4. Capital Investment 2020 BP	2,500	7,500	-	-	10,000
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	2,500	7,500	-	-	10,000
7. Capital Investment variance to BP (4-1)	2,200	2,700	(9,200)	-	(4,300)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,200	2,700	(9,200)	-	(4,300)

(Funding for 2021 will be obtained during the 2021 BP process.)

Risks

If the project is not completed or not completed timely, the concrete facade and window frames will continue to deteriorate. This will result in potential safety issues concerning the spalled concrete and windows falling onto walkways as well as more extensive concrete repairs in the future. In addition, the trash rack guides' anchorage will continue to deteriorate, potentially in an accelerated manner, until the racks free themselves from the guides allowing river debris to enter the unit intakes.

Due to the age of the concrete at the Station and its exposure to the natural elements potentially increasing repair section(s) size, as well as the uncertainty of river conditions, approximately seventeen percent of project value is requested as contingency.

Alternatives Considered

1. Recommendation: NPVRR:$15,214k

2. No other feasible alternative exists for the recommended project. The Company operates the Station under a license from FERC allowing the Company to use water available from the operation of the McAlpine Dam. The license requires the Company to properly maintain the Station structures or return the McAlpine Dam to its condition before the license was issued approximately 100 years ago. Failure to restore the Station as described could subject the Company to the cost of returning the McAlpine Dam to its pre license condition (over $50,000k) and could also render useless the approximately $137,000k spent to date on the Station rehabilitation.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Ohio Falls Masonry and Trash Rack Upgrades project for $14,300k to ensure the façade and window frame deterioration is halted and the trash racks continue to protect generation at the Ohio Falls Generating Station.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment and Contract Proposal for Investment Committee Meeting on: July 27, 2020

Project Name: Canal Coal Fired Assets Demolition
Contract Name (Good/Service): Canal Coal Fired Assets Demolition – Abatement and Demolition

Selected Vendor(s): [redacted]

Contract Authorization Requested: $ 8,600k (Including $1,400k of contingency)

Contract Term: Q4 2021

Total Capital Expenditures Requested: $ 11,800 k (Including $1,900k of contingency including

Total O&M: $0k

Project Number(s): 156485
Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John S Williams

<u>Brief Contract/Project Description</u>

This Authorized Investment Proposal (AIP) seeks approval for the Canal Coal Fired Assets Demolition Project (Project). This approval will be for the full abatement, demolition, and restoration of the former Canal coal-fired generating station site.

This request also seeks Contract Proposal approval to enter into an Abatement and Demolition Agreement (Agreement) for the Canal Coal Fired Assets Demolition – Abatement and Demolition with [redacted] [redacted] [redacted].

The Project was previously approved at a partial sanction to initiate engineering surveys and the technical bidding package. A request is now presented to seek approval to increase the Project sanction to $11,800k to fund the complete abatement, demolition, and restoration of the Canal Generating Station's Coal Fired Facility (Facility), similar to that done on Paddy's Run, Cane Run, Green River, Pineville, and Tyrone stations. This request also seeks approval to award the Agreement to [redacted] in the amount of $8,600k, inclusive of twenty percent (20%) management contingency.

Canal consists of a former coal powerhouse complex, an active switch station along and on the south bank of the approach canal to the Ohio River lock and dam. This former powerhouse complex was developed in the 1880s and includes an approximately 400-foot by 400-foot building which houses four (4) coal-fired generating units, a screen house water intake structure, and sub-

[1] Contractor's Labor and Business Classification Information
Contract NAICS Code: [redacted]
Size Standard – [redacted]
Large or Small Business: [redacted]

surface river intake and discharge tunnels. The northeast wall of the powerhouse structure is integral to the Louisville Metro Flood Protection System. The powerhouse complex has been inactive since the 1970s and contains various hazardous substances, including asbestos and lead-based paints. The structural and mechanical systems are in a continual state of decline and the structures present numerous risks. The demolition of the Facility is being performed to eliminate on-going maintenance and capital costs associated with unmanned structures, potential security/public safety concerns, and other liabilities.

The Agreement will be a lump sum (net salvage) contract for performance of the work, inclusive of five (5) major phases: mobilization, abatement, demolition, restoration and demobilization. The Agreement will be paid out in accordance with a milestone payment schedule commensurate with actual work completed. Individual milestone payments will not exceed the value of the work performed and the maximum monthly cash flow will be limited by the aggregate of the monthly milestones.

Additional components of the contract include but are not limited to:

- Contractor compliance with Company health and safety requirements.
- Termination for convenience and cause.
- Limitation of liability of 125% of the contract price.
- Specific insurance requirements which Company is named as additional insured and contractor waives rights of subrogation. Insurance requirements also include Environmental Liability (pollution) and Public Liability Insurance.
- Indemnification by Contractor including third party claims, personal injury, property damage, claims by government authorities (arising from violation of law), and claims by government authorities for taxes and liens.
- Liquidated damages (LDs) - Guaranteed Substantial Completion Delay
- Three (3) letters of credit totaling $1,400k (20% of $7,200k).

Key Completion Dates:

Mobilization	August	2020
Asbestos Abatement Completion	March	2021
Power-Block Demolition Completion	September	2021
Substantial Completion	November	2021
Final Completion	December	2021

Approximately twenty percent (20%) contract management contingency is requested to address work resulting from exposure to any unknown conditions encountered, as outlined in the "Risk of Contract" section of this document.

<u>Why is the project needed? What if we do nothing?</u>

The powerhouse complex has been inactive since the 1970s and contains various hazardous substances, including asbestos and lead-based paints. The structural and mechanical systems are in a continual state of decline and the structures present numerous risks.

The "Do Nothing" alternative was not considered. The roof is partially collapsed and windows are broken, allowing contaminants (both hazardous and non-hazardous) to disperse and further deteriorate the interior of the building at a much faster rate than before. The existing liability of abating and demolishing the building is already heightened to the extent that few contractors are qualified to execute an abatement and demolition project of this magnitude. If the conditions are allowed to worsen, the costs of abatement will continue to rise. Theft and unauthorized building entrants create a safety liability. There is no certainty that the scrap market will maintain current levels or forecast that it will increase.

<u>Contract Bid Summary</u>
A Request for Quotation (RFQ) was issued to five (5) bidders on March 9, 2020: [redacted] and [redacted]. All bidders were vetted through a thorough pre-qualification process including a financial review by the Credit Department and a safety review. During the RFQ process, [redacted] notified PE of their intent to no-bid the Agreement.

Proposals were received on April 24, 2020 and initial bid presentation meetings were held with each bidder the week of May 4, 2020. The initial bid presentation meetings provided an opportunity for the bidders to present their proposed teams, technical offering, and to demonstrate their understanding of and adherence to scope, schedule and technical requirements. PE and its Owner's Engineer, [redacted] participated in the initial bid presentations.

As part of the initial bid presentations, technical proposal clarification questions were developed and issued to three (3) short-list bidders.

A final bid evaluation was completed after receiving responses to a second round of clarification questions (See Attachment #1). After an extensive review of the proposals, responses to clarification questions, technical capabilities, commercial offering, bid review meetings, and the final proposal evaluation matrix, all three bidders were nearly even in scoring. [redacted] is recommended to execute the project based on its substantially lower price and the lack of commercial edits to the Agreement.

The bid summary is described in Table 1 below:

Table 1

Competing Bids ($ in Thousands)					
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MBE/WBE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Initial Bid Response	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Normalized Bid Response	[redacted]	[redacted]	[redacted]		[redacted]
Total Cost	[redacted]		[redacted]		[redacted]

*Eliminated from consideration due to price.

Additional information on [redacted]:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

<u>Contract Financial Summary</u>
Table 2 below expresses contract spend by year:

Table 2

Contract expenses ($k)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
Amount requested based on contract award estimates	$3,000	$4,200	$0	$0	$7,200
Contingency amount requested	$0	$1,400	$0	$0	$1,400
Total contract authority requested	$3,000	$5,600	$0	$0	$8,600

The Project is included in the 2020 Business Plan (BP) and is adjusted to reflect bid data in the 2021 BP. This adjustment results in an increase of $1,260k above the 2020 BP, which reflects additional PE & Owner Engineering oversight duration, zero-energy verification and air gapping, civil improvements, and future demolition of the Company owned portion of the floodwall integral to the powerblock (to occur once USACE/MSD has constructed its portion of the floodwall).

<u>Project Financial Summary</u>

Financial Detail by Year - Capital ($000s)	**Pre 2020**	**2020**	**2021**	**2022**	**Total**
1. Capital Investment Proposed	-	-	-	-	-
2. Cost of Removal Proposed	252	3,849	7,499	200	11,800
3. Total Capital and Removal Proposed (1+2)	252	3,849	7,499	200	11,800
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	347	4,589	5,604	-	10,540
6. Total Capital and Removal 2020 BP (4+5)	347	4,589	5,604	-	10,540
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	95	740	(1,895)	(200)	(1,260)
9. Total Capital and Removal variance to BP (6-3)	95	740	(1,895)	(200)	(1,260)

*Overage will be obtained through the 2021 BP process.

<u>Risks</u>

The key risks center around the work within the Agreement and are as follows:

- Weather/Schedule – Inclement weather is a moderate risk to the remediation portion of the work. Per the Agreement, this scope of work is to be substantially completed by September 2021. If the work under the Agreement was to experience extended wet weather, for which Force Majeure could be applied, additional contractor costs could be incurred.

- Hazardous Substances Adjustment – To minimize contractor risk pricing for specific hazardous substance conditions, an adjustment provision is incorporated into the Agreement for the following: Hazardous substance that is (i) held in storage containers inside any of the structures of the Facility, (ii) encountered by contractor or a subcontractor in the soil at the Facility, or (iii) any polychlorinated biphenyls that are located in a transformer.

- Flood Protection Levee – The powerhouse is integral to the Louisville Metro Flood Protection System. Thus, a levee modification permit must be approved by the Army Corps of Engineers (ACE). The engineered design of powerhouse demolition will, through selective mechanical and hand demolition methods, maintain the section of powerhouse at the proper elevation and extent to maintain its tie-in at the surrounding Flood Protection Levee. This segment will be demolished at a later date, once the ACE has constructed a new levee on-site. Should the contractor damage the powerhouse to an elevation below the design, it must re-establish the levee protection through approved means.

- Subsurface Bulkheads – The demolition design includes the installation of bulkheads in several areas. Most problematic to install are the screenhouse bulkheads, as the conditions within the intake tunnels (sediment loading and hydraulic connection to the river) are not fully understood. Methods to install the bulkheads may require change once the screenhouse is partially demolished, debris and internal structures removed, allowing divers to inspect the conditions.

<u>Project Alternatives Considered</u>

1. Recommendation:	NPVRR: ($000s) $11,698
2. Do Nothing:	NPVRR: ($000s) N/A

The "Do Nothing" alternative was not considered. The roof is partially collapsed and windows are broken, allowing contaminants (both hazardous and non-hazardous) to disperse and further deteriorate the interior of the building at a much faster rate than before. The existing liability of abating and demolishing the building is already heightened to the extent that few contractors are qualified to execute an abatement and demolition project of this magnitude. If the conditions are allowed to worsen, the costs of abatement will continue to rise. Theft and unauthorized building entrants create a safety liability. There is no certainty that the scrap market will maintain current levels or forecast that it will increase.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Canal Coal Fired Assets Demolition project for $11,800k as well as the Canal Coal Fired Assets Demolition - Abatement and Demolition Agreement for $8,600k to [redacted]

Please see the attached Award Recommendation Approvals page for additional proponent and Project Engineering approvals.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Canal Coal Fired Assets Demolition – Abatement and Demolition Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL

The signatures below recommend that Management approve the Canal Coal Fired Assets Demolition - Abatement and Demolition Agreement for $8,600k to [redacted]

Engineer N/A		Manager – Major Capital Projects John S. Williams (up to $100,000)	
Manager – Contracts, Major Capital Projects Barry Elmore (up to $100,000)		Director – Project Engineering Douglas K. Schetzel ($100,001 up to $500,000)	
Vice President – Project Engineering R. Scott Straight ($500,001 up to $2,000,000)			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

ATTACHMENT #1

CONFIDENTIAL INFORMATION REDACTED

Bidder: [redacted]

Evaluation Factor	Evaluation Factor Weight	Evaluator 1	Evaluator 2	Evaluator 3	Evaluator 4	Evaluator 5	Total	Weighted Score
SAFETY (Company Requirements)	**Pass/Fail**	Pass						
TECHNICAL								
· **Abatement Approach (including project specific safety and documentation)**	**10**	6	7	7	7	x	27	6.75
-- Self-perform or subcontracted?								
-- Water & power management								
-- Waste characterization								
-- Hazard assessment & mitigation								
· **Demolition Approach (including project specific safety)**	**15**	9	9	12	13	x	43	10.75
-- Powerhouse demo plan								
-- Coordination between demolition and abatement								
-- Protection of floodwall								
· **Site Management Plan & Restoration**	**10**	6	5	8	7	x	26	6.50
-- Waste water plan								
-- Scrap recovery process								
-- Cleaning procedure								
-- Backfill plan (basement/tunnels/screenhouse)								
· **Environmental Controls**	**5**	3	4	3	4	x	14	3.50
· **Experience of Proposed Project Team and Adequate Site Staffing**	**5**	2	4	5	5	x	16	4.00
· **Schedule**	**5**	2	2	5	5	x	14	3.50
Total Technical (50)								
COMMERCIAL								
· **Contract Pricing**	**45**	x	x	x	x	36		36.00
· **Clarifications/Exceptions to speciment contract T&C's and Technical Docs**	**5**	x	x	x	x	4		4.00
	100							**75.00**
Total Commercial (50)								

Bidder: [redacted]

Evaluation Factor	Evaluation Factor Weight	Evaluator 1	Evaluator 2	Evaluator 3	Evaluator 4	Evaluator 5	Total	Weighted Score
SAFETY (Company Requirements)	**Pass/Fail**	Pass						
TECHNICAL								
· **Abatement Approach (including project specific safety and documentation)**	**10**	8	9	8	8	x	33	8.25
· **Demolition Approach (including project specific safety)**	**15**	11	11	14	14	x	50	12.50
· **Site Management Plan & Restoration**	**10**	8	7	9	9	x	33	8.25
· **Environmental Controls**	**5**	4	4	5	5	x	18	4.50
· **Experience of Proposed Project Team and Adequate Site Staffing**	**5**	4	5	5	5	x	19	4.75
· **Schedule**	**5**	4	4	5	5	x	18	4.50
COMMERCIAL								
· **Contract Pricing**	**45**	x	x	x	x	19		19.00
· **Clarifications/Exceptions to speciment contract T&C's and Technical Docs**	**5**	x	x	x	x	3		3.00
	100							**64.75**

Bidder: [redacted]

Evaluation Factor	Evaluation Factor Weight	Evaluator 1	Evaluator 2	Evaluator 3	Evaluator 4	Evaluator 5	Total	Weighted Score
SAFETY (Company Requirements)	**Pass/Fail**	Pass						
TECHNICAL								
· **Abatement Approach (including project specific safety and documentation)**	**10**	9	9	9	9	x	36	9.00
· **Demolition Approach (including project specific safety)**	**15**	14	13	14	14	x	55	13.75
· **Site Management Plan & Restoration**	**10**	9	10	10	9	x	38	9.50
· **Environmental Controls**	**5**	4	4	5	5	x	18	4.50
· **Experience of Proposed Project Team and Adequate Site Staffing**	**5**	5	4	5	5	x	19	4.75
· **Schedule**	**5**	4	4	4	5	x	17	4.25
COMMERCIAL								
· **Contract Pricing**	**45**	x	x	x	x	26		26.00
· **Clarifications/Exceptions to speciment contract T&C's and Technical Docs**	**5**	x	x	x	x	4		4.00
	100							**75.75**

Bidder: [redacted]

Evaluation Factor	Evaluation Factor Weight	Evaluator 1	Evaluator 2	Evaluator 3	Evaluator 4	Evaluator 5	Total	Weighted Score
SAFETY (Company Requirements)	**Pass/Fail**	Pass						
TECHNICAL								
· **Abatement Approach (including project specific safety and documentation)**	**10**	5	5	3	3	x	16	4.00
· **Demolition Approach (including project specific safety)**	**15**	7	7	7	8	x	29	7.25
· **Site Management Plan & Restoration**	**10**	5	5	5	5	x	20	5.00
· **Environmental Controls**	**5**	3	3	2	3	x	11	2.75
· **Experience of Proposed Project Team and Adequate Site Staffing**	**5**	2	3	3	2	x	10	2.50
· **Schedule**	**5**	3	2	2	3	x	10	2.50
COMMERCIAL								
· **Contract Pricing**	**45**	x	x	x	x	45		45.00
· **Clarifications/Exceptions to speciment contract T&C's and Technical Docs**	**5**	x	x	x	x	5		5.00
	100							**74.00**

Investment Proposal for Investment Committee Meeting on: 7/27/2020

Program Name: Effluent Limitations Guidelines Program

Total Capital Expenditures: $405,226k (Including $52,860k of contingency)

Total O&M: $9,600k

Project Number(s): Ghent 152965, 162229, 162231 Mill Creek 162230, 152966 Trimble County 152967, 152968

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Joe Strickland / Douglas K. Schetzel

Brief Description of Program

This Authorized Investment Proposal (AIP) seeks approval for the Effluent Limitations Guidelines (ELG) Program.

The Clean Water Act (CWA) establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters. The CWA makes it unlawful to discharge any pollutant from a point source into navigable waters without a permit.

EPA's National Pollutant Discharge Elimination System permit program controls the discharge permitting process. By agreement between the EPA and the Commonwealth of Kentucky, permits are issued and enforced by Kentucky's Department for Environmental Protection and the Division of Water, under the Kentucky Pollutant Discharge Elimination System (KPDES). This means that, for the purposes of ELG, the KPDES permits already reflect the 2015 ELG Rule requirements for Ghent (GH), Trimble County (TC), and Mill Creek (MC) Generating Stations, but will be further impacted when the proposed revisions to the ELG Rule become final. The final ELG Rule's requirements for all pollutants will be imposed and enforced via revisions to the relevant KPDES permits.[1]

This program consists of six projects:

- GH ELG Treatment System, (Expected In-Service 2024)
- TC ELG Treatment System, (Expected In-Service 2023)
- MC ELG Treatment System, (Expected In-Service 2024)
- MC Diffuser, (Expected In-Service 2021)
- GH Diffuser, (Expected In-Service 2021) and

[1] For more information on the history of the ELG Rule, please refer to Gary Revlett's 2020 ECR Filing testimony.

- GH Bottom Ash Transport Water (BATW) Recirculation System. (Expected In-Service 2023)

This program is required to ensure compliance with industry/environmental regulations. This program is ECR recoverable and requires PSC approval. ECR filing was submitted in March 2020 and approval is expected in September 2020. The economic useful life of each project is expected to be 20 years or the end of station life.

Why is the program needed? What if we do nothing?

The program is necessary for each station to comply with the ELG Rule. Test results of the wastewaters regulated by the ELG Rule show that the stations will be out of compliance with the ELG Rule once the revised KPDES permit goes into effect. Without these projects, the stations will continue to be out of compliance resulting in closure of the stations. The generation would then need to be replaced and a Generation Planning analysis shows that the proposed ELG program is preferable to replacing the existing generation at GH, MC and TC.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	23,715	121,152	124,329	136,031	405,227
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	23,715	121,152	124,329	136,031	405,227
4. Capital Investment 2020 BP	22,697	170,347	244,022	61,643	498,709
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	22,697	170,347	244,022	61,643	498,709
7. Capital Investment variance to BP (4-1)	(1,018)	49,195	119,693	(74,388)	93,482
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,018)	49,195	119,693	(74,388)	93,482

*The proposed Capital Investment of $23,715k in 2020 includes of $9,123K pre 2020 spend and $755k of 2020 spend on the non-ECR ELG project that will be moved to ECR when the ECR Order is granted.

Risks

- A risk associated with this program is the delayed receipt of the EPA revised rule. It is expected that the final revision will be forthcoming this fall, but in a presidential election year, it is entirely possible that this rule will not be published until sometime in the more distant future. The problem with pushing the rule off is that until the new rule is published, the existing rule requires compliance with the ELG requirements by the end of 2023. Additional time to comply is expected in the final rule.
- There is also the risk of the Engineering, Procurement, and Construction Agreements (EPC[s]) not meeting commercial operation in advance of the KPDES compliance date. The EPC(s) have provisions for a Contingency Deadline that requires the EPC contractor to have a temporary system in place, two months in advance, if they are not meeting the KPDES limits by the Contingency Deadline Date to reduce this risk.
- There is also the risk that since the preferred technology is a biological process, it is expected to take some time to learn and optimize the performance of the system. It is anticipated that

the KPDES permit will allow for six months of tuning between the ELG Commercial Operation Date and the KPDES compliance date to reduce this risk.

- The risk of an upset condition at the ultimate outfall to the river is expected to be mitigated by installing diffusers at MC and GH; TC already has a diffuser.
- Project Engineering has been working on the ELG Rule since 2014 and has engaged the Environmental Affairs department and the generating station management throughout the entire process.

Alternatives Considered

1. Recommendation:

Ghent NPVRR:	($000s)	$227,460
Mill Creek NPVRR:	($000s)	$120,008
Trimble NPVRR:	($000s)	$78,801

2. A do nothing option was not considered. Without these projects, the stations will continue to be out of compliance with the ELG Rule resulting in closure of the stations. The generation would then need to be replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Effluent Limitations Guidelines program for $405,226k for compliance with the ELG Rule.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital program spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital program spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: **9/29/2020**

Project Name: **Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program**

Previous Authorized Expenditures: **$918,853k (net) (Approved on 10/26/2016)**

Total O&M: **$0.0k**

Amendment Value: **$101,147k (net)**

Total Revised Authorized Capital Expenditures including Amendment: **$1,020,000k (net)**

Project Number(s): **See Attachment #1**

Business Unit/Line of Business: **Project Engineering**

Prepared/Presented By: **Jeffrey B. Heun**

<u>Description of Incremental Ask</u>

This revised Authorized Investment Proposal (AIP) seeks to increase authorization related to the LG&E and KU's CCR Rule Compliance Program. All cost information is net of IMEA and IMPA.

An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start in support of the 2016 ECR filing. A revised AIP for $77,462k ($68,962k in additional funds) was approved on February 24, 2016 to provide funding through 2016, prior to approval of the 2016 ECR filing. A revised AIP for $918,853k ($841,391k in additional funds) was approved on October 26, 2016 for the total program which was based on the 2017 Business Plan (BP). This requested sanction of $1,020,000k ($101,147k in additional funds) is to complete the EPA's CCR Rule Compliance Program and is based on the proposed 2021 BP, inclusive of approximately $22,400k in program management contingency to address unknown and unexpected scope, as summarized below.

	Additional Authorization Approved/Requested	Revised Capital Expenditures Requested
Original Approved Capital Expenditures		$8,500k
1st Revision	$68,962k	$77,462k
2nd Revision	$841,391k	$918,853k
3rd Revision (Amendment Value Requested)	$101,147k	$1,020,000k
2016 ECR Filing[1]		$959,750K

[1] This request authorizes $941,900k compared to the 2016 ECR Filing of $959,750k, when excluding $78,100k for the Mill Creek (MC) Gypsum Dewatering project, which was not included in the 2016 ECR filing.

The EPA's CCR Rule Compliance Program encompassed three (3) major scopes of work outlined below. During execution of these three (3) major scopes of work, several issues were identified which impacted the scope and increased the cost:

1. Closure of wet CCR storage facilities and construction of new Process Water Ponds – approximately $10,000k (~2%) increase.
   - The cost impact for the Auxiliary CCR Pond at E.W. Brown was attributed to an inaccurate cost estimate for the closure, unforeseen delays in receiving the KPDES permit from the State of Kentucky, new incremental KPDES permit requirements to treat water from the impoundment dewatering process, as well as Excusable Events such as wet weather and unexpected scope. The total cost impact from these events was approximately $18,000k.
   - The cost of several sub-projects such as the Process Water System ended up being less than the requested sanction which offset some of the cost impacts above.

2. Construction of new Process Water Facilities (PWS) at the active coal-fired generating stations – approximately $64,000k (~16%) increase.
   - The cost impacts on the PWS projects was the net result of cost increases at Ghent and Mill Creek and cost decreases at Trimble County and E.W. Brown as described below.
   - On the Ghent project, the approximate $52,500k in cost increase was attributed to the initial award being higher than the estimate, moving the location of the PWS after project award, deeper foundations than estimated begin required, station requested changes to the power feeds, adding of redundant equipment, and balance of plant scope that was not included in the EPC contract.
   - On the Mill Creek projects, the approximate $62,000k in net cost increase was attributed to the initial award being higher than the estimate as well as moving forward with a dry pneumatic bottom ash system Coal Combustion Residual Transport (CCRT) scope. The original concept had the submerged flight conveyor (SFC) based system constructed on the ash pond. Moving the location of the SFC system was much more expensive and included schedule conflicts with pond closure that were eliminated by going to a dry system. The dry bottom ash conveying system, at a cost of approximately $90,000k, was the least cost option compared to the wet bottom ash SFC system, at a cost of approximately $107,000k while eliminating the risk for future capital expenditures related to future wet bottom ash water regulations.
   - On the Trimble County project, the approximate cost saving of $3,500k was attributed to the initial award being lower than the estimate.
   - On the E.W. Brown project, the decision to retire Unit 1 and 2 required the Company to re-evaluate the scope of the project. This re-evaluation resulted in an approximate cost savings of approximately $47,000k.

3. Construction of a new Gypsum Dewatering Facility at Mill Creek – approximately $4,800k (~6.5%) increase.
   - The cost increase impacts were attributed to the initial award being higher than the estimate and additional scope that was not included in the EPC contract.

See **Attachment 2** for additional detail on the individual project cost variances.

At the time of the initial sanction request, the EPA's CCR Rule and future Effluent Limitations Guideline (ELG Rule) set forth strict requirements which resulted in limiting options to comply with the rules. Considering the cost impacts outlined above, the chosen compliance alternative would still be the best option to meet current and future EPA regulations.

See **Attachment 3** for copies of all prior signed authorizations.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	**Pre-2020**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	$ 593,361	$ 41,570	$ 19,553	$ -	$ 654,484
2. Cost of Removal Proposed	$ 152,984	$ 73,126	$ 46,977	$ 92,429	$ 365,516
3. Total Capital and Removal Proposed (1+2)	$ 746,346	$114,696	$ 66,530	$ 92,429	$1,020,000
4. Capital Investment 2020 BP	$ 594,858	$ 27,743	$ 11,104	$ 2,464	$ 636,170
5. Cost of Removal 2020 BP	$ 157,240	$ 63,849	$ 36,544	$ 45,102	$ 302,735
6. Total Capital and Removal 2020 BP (4+5)	$ 752,098	$ 91,592	$ 47,648	$ 47,566	$ 938,905
7. Capital Investment variance to BP (4-1)	$ 1,497	$ (13,827)	$ (8,449)	$ 2,464	$ (18,315)
8. Cost of Removal variance to BP (5-2)	$ 4,255	$ (9,277)	$(10,433)	$(47,327)	$ (62,781)
9. Total Capital and Removal variance to BP (6-3)	$ 5,753	$ (23,104)	$(18,881)	$(44,863)	$ (81,095)

Financial Detail by Year - O&M ($000s)	**Pre-2020**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

Project Engineering is requesting approximately $22,400k in program management contingency to address unknown and unexpected scope on the active CCR Rule closure projects, bid uncertainty with the Trimble County Bottom Ash Pond (BAP) and Gypsum Storage Pond (GSP) project, as well as process improvements on the PWS Program (PWS, CCRT, and Gypsum Dewatering projects) that were identified once the projects achieved Commercial Operation and turned over to their respective Generating Stations. See the table below for additional detail on the contingency allocation.

Active CCR Rule closure projects (Approximately 10% of the outstanding work)	$10,000k
Trimble County BAP and GSP project bid uncertainty	$8,000k
Finalization of the PWS Program	$4,400k
Total	$22,400k

Upon approval of this revised investment proposal, Project Engineering will update the AIP's for the projects identified in Attachment 1. The AIP's will be updated to reflect the actual costs on projects that have been completed and sync up with the 2021 BP.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the EPA's CCR Rule Compliance Program project for $1,020,000k (net) to comply with the EPA's CCR Rule. This request authorizes $941,900k compared to the 2016 ECR Filing of $959,750k, when excluding $78,100k for the MC Gypsum Dewatering project, which was not included in the 2016 ECR filing.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Attachment #1

Location	Project #	2021 BP (000's)	2016 ECR Filing (000's)
BR Aux Pond	148824	$30,524	$12,530
GH ATB #1	148827	$47,568	$67,712
GH ATB #2	148828	$87,379	$98,620
GR Main Ash Pond	148831	$13,008	$21,226
GR ATB #2	148832	$15,313	$22,894
MC Ash Pond	148833	$39,354	$46,837
MC Clearwell Pond	148834	$2,120	$2,898
MC Construction Pond	148836	$4,398	$4,504
MC Dead Stoarge Pond	148837	$2,757	$4,286
MC Emergency Pond	148838	$2,584	$8,548
PV Ash Pond	148839	$8,124	$6,974
TY Ash Pond	148840	$8,229	$9,577
TC BAP	148841	$47,879	$54,590
TC GSP	148843	$6,467	$16,147
GH Gypsum Stack	150045	$19,953	$38,257
GR SO2 Pond	150046	$7,093	$9,230
BR Capital	152898	$12,377	$760
GH Capital	152899	$52,725	$1,463
MC Capital (closed)	152901	$11,640	$13,289
MC Frost Land	154574	$1,254	$0
TC Capital (closed)	152902	$726	$721
TC Capital (open)	155513	$7,796	$0
MC Capital (open)	160433	$21,433	$0
BR Carey Land	161073	$351	$0
BR Process water	152377	$25,200	$72,233
GH Process water	152379	$167,104	$115,167
GH Froman Land	153616	$521	$0
MC Process water	152381	$196,900	$134,890
TC Process water	152384	$78,700	$82,197
Totals		**$919,477**	**$845,550**

Location	Project #	2021 BP (000's)	2016 ECR Filing (000's)
MC Gypsum Dewatering	152330	$75,125	$73,303
MC Gypsum PST Replacement	162240	$2,975	$0
Totals		**$78,100**	**$73,303**

Program Contingency	**$22,423**
Program Total Authorization	**$1,020,000**

CONFIDENTIAL INFORMATION REDACTED

Attachment #2

CCR Rule Compliance Program - ECR & AIP Comparison

August 13, 2020

Station	Project	2016 ECR Filing	Original Project Sanction (2016)	2021 BP AIP Adjustment	Notes
Brown		**$101,307,000**	**$85,523,000**	**$68,452,000**	
Brown	Capital	$68,613,000	$760,000	$12,377,000	Based on Updated 2021BP (no contingency)
Brown	Aux Pond Capping	$32,694,000	$12,530,000	$30,875,000	Based on Updated 2021BP (no contingency)
Brown	Process Water System	$0	$72,233,000	$25,200,000	Based on Updated 2021BP
Ghent		**$364,177,000**	**$321,219,000**	**$375,250,000**	
Ghent	Capital	$114,290,000	$1,463,000	$52,725,000	Based on Updated 2021BP (no contingency)
Ghent	ATB #1 Capping & Secondary Pond Cleanout	$72,881,000	$67,712,000	$47,568,000	Based on Updated 2021BP (no contingency)
Ghent	ATB #2 Capping	$92,918,000	$98,620,000	$87,379,000	Based on Updated 2021BP (no contingency)
Ghent	Gypsum Stack Cooling Pond & Reclaim Pond Cleanout	$84,088,000	$38,257,000	$19,953,000	Based on Updated 2021BP (no contingency)
Ghent	Process Water System	$0	$115,167,000	$167,625,000	Based on Updated 2021BP (no contingency)
Green River		**$56,829,000**	**$53,350,000**	**$35,414,000**	
Green River	Main Ash Pond Capping	$20,204,000	$21,226,000	$13,008,000	Based on Updated 2021BP (project completed)
Green River	ATB #2 Capping	$21,436,000	$22,894,000	$15,313,000	Based on Updated 2021BP (project completed)
Green River	SO2 Pond Cleanout	$15,189,000	$9,230,000	$7,093,000	Based on Updated 2021BP (project completed)
Mill Creek		**$196,941,000**	**$215,252,000**	**$282,440,000**	
Mill Creek	Capital (Open)	$0	$0	$21,433,000	Based on Updated 2021BP (no contingency)
Mill Creek	Capital (Closed)	$121,361,000	$13,289,000	$12,894,000	Based on Updated 2021BP (project completed)
Mill Creek	Ash Pond Capping	$50,976,000	$46,837,000	$39,354,000	Based on Updated 2021BP (no contingency)
Mill Creek	Clearwell Pond Cleanout	$5,369,000	$2,898,000	$2,120,000	Based on Updated 2021BP (project completed)
Mill Creek	Construction Pond Cleanout	$7,283,000	$4,504,000	$4,398,000	Based on Updated 2021BP (project completed)
Mill Creek	Dead Storage Pond Cleanout	$6,433,000	$4,286,000	$2,757,000	Based on Updated 2021BP (project completed)
Mill Creek	Emergency Pond Cleanout	$5,519,000	$8,548,000	$2,584,000	Based on Updated 2021BP (project completed)
Mill Creek	Process Water System & CCRT	$0	$134,890,000	$196,900,000	Based on Updated 2021BP
Pineville		**$8,009,000**	**$6,974,000**	**$8,124,000**	
Pineville	Ash Pond Capping	$8,009,000	$6,974,000	$8,124,000	Based on Updated 2021BP (project completed)
Trimble Co. (Net)		**$219,384,000**	**$153,655,000**	**$141,568,000**	
Trimble Co.	Capital	$88,739,000	$721,000	$8,522,000	Based on Updated 2021BP (no contingency)
Trimble Co.	Ash Pond Capping	$101,747,000	$54,590,000	$47,879,000	Based on Updated 2021BP
Trimble Co.	Gypsum Pond Capping	$28,898,000	$16,147,000	$6,467,000	Based on Updated 2021BP
Trimble Co.	Process Water System	$0	$82,197,000	$78,700,000	Based on Updated 2021BP
Tyrone		**$13,103,000**	**$9,577,000**	**$8,229,000**	
Tyrone	Ash Pond Capping	$13,103,000	$9,577,000	$8,229,000	Based on Updated 2021BP (project completed)
	Projected ECR Total	**$959,750,000**	**N/A**	**$919,477,000**	
	Delta to ECR Filing	**$0**	**N/A**	**$40,273,000**	

Station	Project	2016 ECR Filing	Original Project Sanction (2016)	2021 AIP Adjustment	Notes
Mill Creek	Gypsum Dewatering (NOT INCLUDED IN ECR FILING)	$0	$73,303,000	$78,100,000	Based on Updated 2021BP
	Projected CCR Rule Program Total	**N/A**	**$918,853,000**	**$997,577,000**	
	Delta to Project Sanction	**N/A**	**$0**	**($78,724,000)**	

Revsied CCR Rule Program Sanction

Projected CCR Rule Program Total	[redacted]	[redacted]	[redacted]	CCR Rule
Requsted Program Contingency	[redacted]	[redacted]	[redacted]	PWS and MC Gypsum
Revised Sanction Request	[redacted]	[redacted]	[redacted]	

Revsied CCR Rule ECR Approval

Projected ECR Total	**$919,477,000**
Requsted Program Contingency	**$22,423,000**
Revised Projected ECR Total	**$941,900,000**
Delta to ECR Filing	[redacted]

Authorized Investment Proposal for Investment Meeting on: October 26, 2016

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program

CCR Rule Closure, CCR Rule Capital[1], Process Water

E.W. Brown:	$85,523k
Ghent:	$321,219k
Green River:	$53,350k
Pineville:	$6,974k
Tyrone:	$9,577k
Mill Creek:	$215,252k
Trimble Co. (LGE) net/gross	$79,900k/$106,534k
Trimble Co. (KU) net/gross	$73,754k/$98,339k

CCR Rule Sanction Request: $845,550k (net)/$896,768k (gross)
Previous Approval: $77,462k (net)

Mill Creek Gypsum Dewatering: **$73,303k**

Total Sanction Request: $918,853k (net)/$970,071k (gross)
Project Numbers: See list of project numbers on page 5

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Jeff Oeswein/Joe Strickland

Executive Summary

This revised Authorized Investment Proposal (AIP) is seeking full project authorization, under the 2016 ECR Filing, to continue compliance construction and closure activities associated with the project development, conceptual and final design, permitting, closure and construction activities to comply with the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and became effective on October 19, 2015.

This document seeks to increase the approval of the CCR Rule Compliance Program spend to $845,550k (net)/$896,768k (gross) for the scope listed below. It is important to note that the requested authorization is based on CCR Beneficial Use and does not include a sensitivity of an additional $622,000k (per the 2016 Business Plan (BP)) if beneficial use is not utilized. This revised approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to location restrictions, design criteria, operating criteria, groundwater monitoring, as well as conceptual and final design, permit development, and construction activities at all the generating

[1] CCR Rule Capital is for new construction activities, not including the Process Water systems that will remain in place and serve the Plants generation needs after compliance with the CCR Rule. An example is new process ponds.

stations. This document also seeks approval for the Mill Creek Gypsum Dewatering project spend for $73,303k. The total amount seeking approval for the CCR Rule Compliance Program and the Mill Creek Gypsum Dewatering is $918,853k (net).

An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start in support of the 2016 ECR filing. A revised AIP for $77,462k (net) was approved on February 24, 2016 to provide funding through 2016, prior to approval of the 2016 ECR filing. This requested $918,853k sanction approval is for the total program included in the 2017 BP.

The overall scope of this project includes the design, permitting and final closures of all CCR impoundments at the stations listed above. The scope also includes the design and construction of new process water systems to manage the on-going operation at E.W. Brown, Ghent, Mill Creek and Trimble County related to water usage, treatment and discharge within current permit conditions once the current impoundments are taken out of service and closure activities begin. This CCR Rule Compliance Program scope does not include treatment equipment associated with the EPA effluent limitations guidelines ("ELG") rule for any generating station. While Ghent, Brown and Trimble County stations have new landfill projects which include CCR Treatment (CCRT) scopes for the dewatering and dry handling of CCR, Mill Creek does not. This program also includes the CCRT scopes for Mill Creek consisting of a new gypsum dewatering facility, a new bottom ash dewatering system, and the dry fly ash transport systems that are similar to the CCRT programs at the other stations. Also included in this scope is the smaller compliance activities, including Trimble County's Bottom Ash Pond (BAP) berm stability project, Mill Creek's ash pond hydraulic and hydrological (H&H) and berm height increase projects, Mill Creek's gypsum stack-out pad reconstruction and the Ghent H&H construction on Ash Treatment Basin (ATB) #1 and #2.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the draft CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of eight samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all wet CCR Impoundments and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Companies") current long term CCR Storage plans. It is anticipated that closure of Companies CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6-months after and to be closed within five years of a groundwater exceedance. It is assumed that closure must start by the first quarter of 2019, based on a groundwater exceedance.

This request is seeking approval of $918,853k for project development, conceptual and final design, permitting, and compliance construction activities. Project development includes the structural stability, safety factor, and design flood assessments for each facility under the CCR Rule. The conceptual design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for final design. Final design will build upon the results of the conceptual design and will allow the Companies to submit the necessary state permits as well as develop construction drawings and specifications for closure activities.

Procurement & Schedule

The structural stability, safety factor and design flood assessment assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) were completed in 2015, while the remainder of the assessments were completed in 2016. Issues identified during the assessments lead by Generation Engineering were handed off to Project Engineering to implement. The assessments and construction to address the issues must be in progress by October 17, 2016. During the 2015 assessments, two issues were identified: Trimble County BAP factor of safety and Mill Creek Ash Pond H&H. To address the Trimble County BAP factor of safety, a rock abutment was installed in late 2015. For the Mill Creek Ash Pond H&H issue, a new principal spillway is being installed and the height of the embankments is being raised. In 2016 it was determined that modifications to Ghent's ATB #1 and ATB #2 were needed to comply with CCR Rule H&H requirements. Work is in process to install a larger emergency spillway on ATB #1 and modify the existing emergency spillway on ATB #2.

Project Engineering has reviewed proposals for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. Upon completion of Project Engineering's bid review, the Ghent and Mill Creek conceptual design scopes were awarded to AECOM while Amec was awarded the E.W. Brown and Trimble County projects. The Green River project was awarded to [redacted] under a Sole Source Agreement. Project Engineering awarded the engineering work to three different engineering firms in an effort to apply lessons learned and best practices between the owner's engineers.

Project Cost

The overall cost to comply with the EPA's CCR Rule utilizing CCR Beneficial Use is $918,853k (net) per the 2017 BP (Table 2), which includes $441,063k (net) for CCR impoundment closure and new capital, and an additional $404,487k (net) for construction of process water systems and CCR handling facilities[2] and $73,303k for Mill Creek's gypsum dewatering facility. This revised approval seeks full authorization for project development, conceptual/final design, permitting, and construction activities. Requested authorization per station/project is shown in Table 1.

Other Alternatives Considered

For project development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies were

[2] New CCR handling facilities are primarily at Mill Creek.

completed by the second quarter of 2016 to allow adequate time to implement corrective action by October 17, 2016, or the facility will be forced to begin the closure process.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

Below are the alternatives considered for the projects:

1. Recommendation:	NPVRR: $978,018k
CCR Rule Closure, CCR Rule Capital[3], Process Water	
E.W. Brown:	$102,056k
Ghent:	$356,030k
Green River:	$60,577k
Pineville:	$7,772k
Tyrone:	$10,909k
Mill Creek:	$262,005k
Trimble Co. (LGE) (net):	$92,873k
Trimble County (KU) (net):	$85,798k
2. Do Nothing[4]:	NPVRR: $0

Below are the alternatives considered for the Mill Creek Gypsum Dewatering projects:

1. Recommendation: Mill Creek Gypsum Dewatering	NPVRR: $86,634k
2. Do Nothing:	NPVRR: $0

Table 1 below shows a breakout of cost by station and project number for the current authorization request and does not reflect previous authorization request. Cost associated with the previous request will be reallocated to the corresponding new projects:

[3] CCR Rule Capital is for new construction activities, excluding process water systems, which will remain in place and serve the plants generation needs after compliance with the CCR Rule. An example is new process ponds.

[4] A Do Nothing alternative is not a viable option as this project is a regulatory requirement from the EPA.

Table 1[5]

Location	Project #	2017 BP (000's)	2016 ECR Filing (000's)
BR Aux Pond	148824	$12,530	$29,651
GH ATB #1	148827	$67,712	$48,630
GH ATB #2	148828	$98,620	$92,918
GH Gypsum Stack	150045	$38,257	$84,088
GR Main Ash Pond	148831	$21,226	$19,786
GR ATB #2	148832	$22,894	$21,436
GR SO2 Pond	150046	$9,230	$15,189
MC Ash Pond	148833	$46,837	$47,743
MC Clearwell Pond	148834	$2,898	$5,369
MC Construction Pond	148836	$4,504	$7,283
MC Dead Storage Pond	148837	$4,286	$6,433
MC Emergency Pond	148838	$8,548	$5,519
PV Ash Pond	148839	$6,974	$8,009
TC BAP	148841	$54,590	$94,739
TC GSP	148843	$16,147	$28,898
TY Ash Pond	148840	$9,577	$13,103
BR Capital	152898	$760	$68,613
GH Capital	152899	$1,463	$114,290
MC Capital	152901	$13,289	$121,361
TC Capital	152902	$721	$88,739
BR Process Waters	152377	$72,233	$0
GH Process Waters	152379	$115,167	$0
MC Process Waters	152381	$134,890	$0
TC Process Waters	152384	$82,197	$0
Totals		**$845,550**	**$921,797**

Location	Project #	2017 BP (000's)	2016 ECR Filing (000's)
MC Gypsum Dewatering	152330	$73,303	$0

Table 2 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year (net):

[5] Trimble County numbers are Net. The Capital and Process Water projects were combined in the ECR filing but were subsequently separated into standalone projects for tracking purposes.

Table 2[6]

$Millions	2016	2017	2018	2019	2020	2021	2022	2023	Totals
2017 BP	$43.6	$156.3	$299.1	$120.6	$56.8	$59.9	$69.8	$39.4	**$845.6**
2016 ECR	$39.5	$237.5	$283.6	$93.3	$95.6	$72.0	$68.1	$32.3	**$921.8**
Variance	($4.1)	$81.2	($15.5)	($27.3)	$38.7	$12.1	($1.7)	($7.2)	**$76.2**

The amounts incurred in Table 2 prior to approval of the 2016 ECR filing were recorded as non-mechanism, all future changes will be mechanism under the approved 2016 ECR filing. Table 3 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year for the Mill Creek Gypsum Dewatering:

Table 3

$Millions	2016	2017	2018	2019	2020	2021	2022	2023	Totals
2017 BP	$0.3	$28.6	$44.4	$0.0	$0.0	$0.0	$0.0	$0.0	**$73.3**
2016 ECR	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**$0.0**
Variance	($0.3)	($28.6)	($44.4)	$0.0	$0.0	$0.0	$0.0	$0.0	**($73.3)**

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000's)	Pre-2016	2016	2017	2018	Post 2018	Total
Capital Investment Proposed	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal Proposed	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal Proposed	-	43,927	184,892	343,528	346,506	918,853
Capital Investment 2017 BP	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal 2017 BP	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal 2017 BP	-	43,927	184,892	343,528	346,506	918,853
Capital Investment variance to BP	-	-	-	-	-	-
Cost of Removal variance to BP	-	-	-	-	-	-
Total Capital and Removal variance to BP	-	-	-	-	-	-

[6] Numbers are based on Trimble County Net costs.

Financial Summary ($000's):

Below is the financial analysis for the project:

Financial Analysis -Project Summary ($000)	Project CCR Rule, PWS, New Construction	2016	2017	2018	2019	2020	Life 2016-2059
Project Net Income	Brown	$79	$1,332	$3,603	$4,231	$5,118	$78,717
	Ghent	$363	$2,788	$7,326	$9,043	$10,755	$318,435
	Green River	$112	$305	$1,431	$3,192	$2,639	$45,185
	Mill Creek	$1,425	$4,096	$8,783	$10,094	$10,562	$199,506
	Tyrone	$16	$39	$299	$573	$474	$8,133
	Pineville	$14	$32	$112	$417	$345	$5,823
	TC LGE	$156	$1,042	$2,546	$2,999	$3,274	$74,779
	TC KU	$144	$962	$2,350	$2,768	$3,022	$72,559
Project ROE							
	Brown	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Ghent	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Green River	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Mill Creek	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Tyrone	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Pineville	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	TC LGE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	TC KU	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%

Summary ($000)	Project	2016	2017	2018	2019	2020	2016-2059
Project Net Income	MC Gypsum Dewatering	$0	$1,484	$3,518	$3,312	$3,449	$56,298
Project ROE							
	MC Gypsum Dewatering	0.0%	9.6%	9.4%	9.2%	9.6%	9.9%

Environmental Risks:

There are no environmental risks related to New Source Review associated with this project.

Conclusions and Recommendation

It is recommended that this revised Authorized Investment Proposal be approved to provide full funding, per the 2017 BP and in concert with the 2016 ECR Filing, in the amount of $918,853k (net) as outlined in the 2017 BP. Work under this authorization includes, Project Development, Conceptual and final design, permitting and construction activities for the EPA's CCR Rule compliance program impoundment closure activities, new CCR Rule related process water systems, and Mill Creek's gypsum dewatering, bottom ash and dry fly ash handling systems.

Kent W. Blake Chief Financial Officer	Victor A. Staffieri Chairman, CEO and President

Authorized Investment Proposal for Investment Meeting on: February 24, 2016

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program

LG&E:	$250k[1]
KU:	$250k[2]
E.W. Brown:	$1,025k
Ghent:	$35,595k
Green River:	$4,148k
Mill Creek:	$31,835k
Pineville:	$323k
Trimble County:	$3,616k (net)
Tyrone:	$920k
Total Sanction Request:	**$77,462k (net)[3]**
Previous Approval:	$8,500k

Project Numbers: 147098, 147099, 147965, 147966, 147967, 147968. 147969, 147971, 147972, 147973

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Jeff Oeswein

Executive Summary

This revised Authorized Investment Proposal (AIP) is being submitted for the continuation of compliance activities associated with the Project Development, Conceptual Design, Permitting and Construction to comply with the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and became effective on October 19, 2015.

This document seeks to increase the approval of the CCR Rule Compliance Program spend to $77,462k (net) for the scope listed below. This revised sanction request is only to cover spend through 2016, in agreement with the 2016 ECR Filing Plan (Table 2). This request seeks approval for an incremental portion of the overall CCR Rule Compliance Program which is $959,749k (net), assuming the ability of CCR Beneficial Use in constructing the closure plans at each pond. It is important to note that the 2016BP amounts do not include a sensitivity of an additional $622,000k

[1] This project was initially opened to allow early CCR Rule compliance development activities to begin. The amounts shown have been included in the Mill Creek Project. This project will be closed upon approval of ECR filing and expenditures reallocated to the Mill Creek Project.
[2] This project was initially opened to allow early CCR Rule compliance development activities to begin. The amounts shown have been included in the Ghent Project. This project will be closed upon approval of ECR filing and expenditures reallocated to the Ghent Project.
[3] Total Sanction Request is based on spend though 2016, per the 2016 ECR Filing Plan, and does not take into account previous sanction requests. This request seeks to reallocate previous authorizations to match up with the current CCR Rule plan. Costs for the Cane Run Project are no longer included in this AIP request.

if beneficial use is not approved. This revised approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to Location Restrictions, Design Criteria, Operating Criteria, Groundwater Monitoring, as well as Conceptual and Final Design, Permit Development, and Construction Activities at Ghent and Mill Creek. An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start prior to this Investment Committee authorization request. The requested $77,462k sanction approval was included in the 2016 Business Plan. Upon approval of the 2016 ECR filing, Project Engineering (PE) will submit a revised AIP requesting the full authorization of the CCR Rule and move the project to mechanism capital (Environmental Cost Recoverable).

The overall scope of this project includes the design, permitting and final closures of all CCR ponds at the stations listed above. The scope also includes the design and construction of new process water systems to manage the on-going operation at Brown, Ghent, Mill Creek and Trimble County related to water usage, treatment and discharge with current permit conditions. This CCR Rule Compliance Program scope does not include treatment equipment associated with the EPA effluent limitations guidelines ("ELG") rule. While Ghent, Brown and Trimble County stations have new landfill projects which include CCRT scopes for the dewatering and dry handling of CCR, Mill Creek does not. This Program also includes a new bottom ash dewatering facility that is similar to the CCRT programs at the other stations. Also included in this scope is the smaller compliance activities at Trimble County (BAP berm stability project), Mill Creek's ash pond berm height increase, Mill Creek's gypsum stackout pad reconstruction and the Mill Creek ash pond discharge structure and piping.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR Impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the DRAFT CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of 8 samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all CCR Impoundments and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Company") current long term CCR Storage plan. It is anticipated that closure of LG&E and KU's CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6-months after and to be closed within 5 years of a groundwater exceedance.

This request is seeking approval of $77,462k for Project Development, Conceptual Design, Final Design, Permitting, and Compliance Construction activities. Project Development includes the structural stability, safety factor, and design flood assessments for each facility under the CCR Rule. The Conceptual Design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for Final Design. Final Design will build upon the results of the Conceptual Design and will allow the Company to submit the necessary state permits as well as develop construction drawings and specifications for closure activities. Initial construction activities include, but are not limited to: Trimble County Buttress (completed), Mill Creek Stackout Pad (ongoing), Mill Creek Hydraulic & Hydrological (H&H) modifications, Ghent ATB #1 reactivation, Ghent Gypsum Stack reclamation and hauling to ATB #2, and preliminary closure activities at the Mill Creek Clearwell and Dead Storage ponds. A Certificate of Public Convenience and Necessity (CPCN) and Environmental Cost Recovery (ECR) filing was submitted to the Kentucky Public Service Commission (KPSC) on January 29, 2016 for approval of the overall project.

Procurement & Schedule

Generation Engineering is currently working with existing engineering firms to address the structural stability, safety factors, and design flood assessments. The assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) were completed in 2015, while the remainder of the assessments will be completed by early 2016. If issues are identified during the assessments, construction plans will be developed and handed off to Project Engineering to implement. The assessments and construction to address the issues must be completed by October 17, 2016. During the 2015 assessments, two issues were identified: Trimble County Bottom Ash Pond factor of safety and Mill Creek Ash Pond H&H. To address the Trimble County BAP factor of safety, a rock abutment was installed in late 2015. For the Mill Creek Ash Pond H&H issue, engineering is ongoing and construction will commence in late first quarter or early second quarter of 2016 to meet the October 17, 2016 deadline.

Project Engineering has reviewed proposals for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. Upon completion of Project Engineering bid review, the Ghent and Mill Creek projects were awarded to AECOM while Amec was awarded the E.W. Brown and Trimble County projects. The Ghent and Mill Creek projects are critical due to the size of the work and logistics required to implement the closure plan. Project Engineering awarded the engineering work to two different contractors in an effort to apply lessons learned and best practices between the engineering firms.

Project Cost

The overall cost to comply with the EPA's CCR Rule utilizing CCR Beneficial Use is $959,749k (net) per the 2016 ECR Filing Plan (Table 2), which includes $566,746k (net) for CCR impoundment closure, and an additional $393,003k (net) for new construction of process water systems and CCR handling facilities, primarily at Mill Creek. This revised approval seeks $77,462k (net) for Project Development, Conceptual/Final Design, Permitting, and Construction activities. Requested authorization per station/project is shown in Table 1.

Other Alternatives Considered

For Project Development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies were completed in the 4th Quarter of 2015 to allow adequate time to address inadequacies by October 17, 2016, or the facility will be forced to begin the closure process.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

Below are the alternatives considered for the projects:

1. Recommendation: NPVRR: ($000s)
   - Project 147965: Brown CCR Ruling – Non Mech. $1,397
   - Project 147966: Ghent CCR Ruling – Non Mech. $47,503
   - Project 147967: Green River CCR Ruling – Non Mech. $5,336
   - Project 147968: Pineville CCR Ruling – Non Mech. $417
   - Project 147969: Tyrone CCR Ruling – Non Mech. $1,184
   - Project 147971: Mill Creek CCR Ruling – Non Mech. $41,248
   - Project 147972: Trimble Co. (LGE) CCR Ruling – Non Mech. $2,614
   - Project 147973: Trimble Co. (KU) CCR Ruling – Non Mech. $2,615
   - Project 147098: CCR Ruling Engineering - LGE $316
   - Project 147099: CCR Ruling Engineering - KU $315
2. Do Nothing: NPVRR: ($000s) $0
3. Next Best Alternative(s): NPVRR: ($000s) $0

Table 1 below shows a breakout of cost by station and project number for the current authorization request:

Table 1

Location	Project #	Previous AIP ($000's)	2016 BP ($000's)	2016 ECR Filing ($000's)
LG&E	147098	$250	-	-
KU	147099	$250	-	-
E.W. Brown	147965	$750	$10,588	$1,025
Ghent	147966	$750	$35,528	$35,595
Green River	147967	$3,250	$4,148	$4,148
Pineville	147968	$625	-	$323
Tyrone	147969	$625	-	$920
Cane Run	147970	$500	-	-
Mill Creek	147971	$750	$26,453	$31,835
Trimble Co. (LGE) (net)	147972	$390	$2,011	$1,880
Trimble Co. (KU) (net)	147973	$360	$1,856	$1,736
Totals		**$8,500**	**$80,584**	**$77,462**

Table 2 below shows the 2016 Business Plan and 2016 ECR filing costs broken out by year (net):

Table 2

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	2021	2022	2023	**Totals**
2016 BP	$4,824	$75,760	$235,572	$277,695	$83,054	$90,814	$79,972	$73,126	$32,183	**$953,000**
2016 ECR	$5,561	$71,901	$237,492	$283,604	$93,267	$95,554	$71,976	$68,108	$32,286	**$959,749**

The amounts incurred prior to approval of the 2016 ECR filing will be recorded as non-mechanism and moved to mechanism when the project receives ECR approval, currently anticipated for the third quarter of 2016.

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	Pre-2015	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	-	751	36,586			37,337
2. Cost of Removal Proposed	-	2,155	37,970			40,125
3. Total Capital and Removal Proposed (1+2)	-	2,906	74,556	-	-	77,462
4. Capital Investment 2016 BP		-	46,149	159,177	187,677	393,003
5. Cost of Removal 2016 BP	-	4,824	29,611	76,395	449,168	559,996
6. Total Capital and Removal 2016 BP (4+5)	-	4,824	75,760	235,572	636,845	953,000
7. Capital Investment variance to BP (4-1)	-	(751)	9,563	159,177	187,677	355,666
8. Cost of Removal variance to BP (5-2)	-	2,669	(8,359)	76,395	449,168	519,872
9. Total Capital and Removal variance to BP (6-3)	-	1,917	1,204	235,572	636,845	875,538

Financial Summary ($000's):

Below is the financial analysis for the project:

Financial Analysis - Project Summary ($000)	Project	2015	2016	2017	2018	2019	Life 2015-2055
Project Net Income							
	LG&E	$6	$15	$12	$12	$11	$197
	KU	$5	$12	$11	$12	$11	$204
	E.W. Brown	$11	$22	$38	$54	$54	$1,175
	Ghent	$232	$464	$1,169	$1,873	$1,873	$38,069
	Green River	$26	$52	$136	$220	$248	$3,802
	Pineville	$9	$17	$17	$17	$19	$323
	Tyrone	$12	$23	$36	$49	$55	$867
	Mill Creek	$212	$424	$1,049	$1,674	$1,674	$29,177
	Trimble-LGE	$46	$93	$96	$100	$100	$2,171
	Trimble-KU	$43	$87	$89	$92	$92	$2,006
Project ROE							
	LG&E	19.8%	15.2%	9.6%	9.8%	9.8%	10.1%
	KU	19.7%	13.2%	8.6%	9.8%	9.8%	9.9%
	E.W. Brown	83.6%	7.6%	7.0%	10.0%	10.0%	9.7%
	Ghent	96.7%	4.8%	6.2%	10.0%	10.0%	9.6%
	Green River	252.7%	4.7%	6.2%	10.0%	11.4%	9.5%
	Pineville	309.4%	19.4%	10.0%	10.0%	11.4%	10.3%
	Tyrone	416.5%	9.4%	7.4%	10.0%	11.4%	9.8%
	Mill Creek	161.5%	5.0%	6.3%	10.0%	10.0%	9.5%
	Trimble-LGE	29.1%	14.1%	9.7%	10.0%	10.0%	10.1%
	Trimble-KU	28.6%	14.2%	9.7%	10.0%	10.0%	10.1%

Environmental Risks:

There are no environmental risks related to New Source Review associated with this project.

Conclusions and Recommendation

It is recommended that this revised Authorized Investment Proposal be approved to cover the estimated spend through the end of 2016 in the amount of $77,462k to perform Project Development, Conceptual and Final design, Permitting and Construction activities for the EPA's CCR Rule Compliance Program. Sanction request for the remaining project spend will be requested upon approval of the 2016 KPSC ECR filing.

KtWBlake

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Authorized Investment Proposal for Investment Meeting on: June 30, 2015

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule – Impoundment Closure

CCR Rule Conceptual Design: $5,000k
Green River Construction Inactive Status: $2,500k
Cane Run Closure Activities: $500k
Previous Approval: $500k
Total Sanction Request: $8,500k

Project Numbers: 147098, 147099, 147965, 147966, 147967, 147968. 147969, 147970, 147971, 147972, 147973

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Gary Revlett

Executive Summary

This Authorized Investment Proposal (AIP) is being submitted for Project Development, Conceptual Design, and Initial Construction related to the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and will become effective on October 17, 2015.

This document seeks approval of the CCR Rule – Impoundment Closure project spend of $8,000k for the conceptual scope listed below. This request seeks approval for an incremental portion of the overall Impoundment Closure which is $557,418k gross ($522,898k net), per the 2015 Business Plan (Table 3), $5,000k for project development/conceptual design and $3,000k for early closure of various ponds listed herein. This initial approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to Location Restrictions, Design Criteria, Operating Criteria, and Groundwater Monitoring, as well as construction activities to move active CCR storage facilities into an inactive status. An AIP for $500k ($250k for LG&E and $250k for KU) was submitted on April 2, 2015 to allow engineering activities to start prior to this Investment Committee authorization request. This request is seeking an additional $8,000k approval on top of the previously approved $500k. The 2015 amount is $500k higher than the budget but has been fully funded by the RAC as non-mechanism capital.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the DRAFT CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of 8 samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all CCR Impoundment and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Company") current long term CCR Storage plan. It is anticipated that closure of LG&E and KU's CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6 months after and to be closed within 5 years of a groundwater exceedance.

This request is seeking approval of $5,500k for Project Development and Conceptual Design. Project Development includes the structural stability, safety factor, and design flood assessments as well as development of the groundwater monitoring plan for each facility. The Conceptual Design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for Final Design. A Certificate of Public Convenience and Necessity (CPCN) and Environmental Cost Recovery (ECR) filing will be made to the Kentucky Public Service Commission (KPSC) for approval of the overall project in late 2015. In conjunction with the KPSC filing, Project Engineering will seek Investment Committee approval for the overall CCR Rule – Impoundment Closure project.

This request is seeking approval of $3,000k for engineering and initial construction activities that would allow Green River ATB #2, and Green River SO_2 ponds to attain "Inactive" status and final closure of Cane Run's impoundments as part of the ongoing Ash Pond and Landfill closure project. If a CCR storage facility is "Inactive", as defined in the CCR Rule, the company is not required to perform: structural stability, safety factor, design flood assessments, location restriction, or groundwater monitoring, but must close the facility by April 17, 2018. In addition, LG&E and KU are not required to perform 30-years of groundwater monitoring and publication of test results on the Company's website per the CCR Rule's requirements. However, the facilities will be closed under State requirements which will require a minimum of 5-years of groundwater monitoring and submittal of test results to the State. To attain "Inactive" status, the CCR storage facility must stop receiving CCR material by October 14, 2015 and be closed by April 17, 2018.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

Below are the alternatives considered for project:

1. Recommendation:

	NPVRR: ($000s)
Project 147965	$1,011
Project 147966	$1,011
Project 147967	$4,452
Project 147968	$835
Project 147969	$847
Project 147970	$608
Project 147971	$1,010
Project 147972	$527
Project 147973	$488
Project 147098	$330
Project 147099	$331

2. Do Nothing: NPVRR: ($000s) $0
3. Next Best Alternative(s): NPVRR: ($000s) $0

Procurement & Schedule

Generation Engineering is currently working with existing contractors to address the structural stability, safety factors, and design flood assessments. Generation Engineering is working within existing contracts or will be issuing new contracts against master service agreements. The assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) are scheduled to be completed by the end of 2015 with the remainder of the assessments completed by early 2016. If issues are identified during the assessments, construction plans will be developed and handed off to Project Engineering to implement. The assessments and construction to address the issues must be completed by October 17, 2016.

Currently, Project Engineering is developing the scope of work and Request for Quotation (RFQ) package for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. The current plan is to issue the RFQ package by the end of the 3rd quarter of 2015 and award the engineering work no later than December 2015. The RFQ package will be structured to award the engineering and owner's engineering service to one contractor for the entire fleet or to choose multiple contractors and award the work plant specific.

Project Cost

The overall gross cost of the EPA's CCR Rule is $557,418k ($522,898k net) per the 2015 Business Plan (Table 3), which includes $554,319k gross cost ($520,282k net) for CCR impoundment closure, and an additional $3,099k gross cost ($2,616k net) for construction of new process ponds once the CCR impoundments are taken out of service. This initial approval seeks $5,500k for Project Development/Conceptual Design, $2,500k for construction activities to attain "Inactive" status, and $500k for closure of the Cane Run CCR impoundment as part of the ongoing landfill and ash pond closure project. Requested authorization per location is shown in Table 1 while estimated cash flows are shown in Table 2.

Other Alternatives Considered

For Project Development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies must be completed in the 3rd Quarter of 2015 to allow adequate time to address inadequacies by October 17, 2016, or the facility will be forced to begin the closure process.

For Initial Construction activities to attain Inactive Status, a "do nothing" alternative was considered. A "do nothing" alternative would require the closure of the Green River ATB #2 under the full CCR Rule. A "do nothing" alternative would not affect the closure of the Cane Run Impoundments due to ongoing work or the Green River SO_2 Pond, as it's currently inactive. Closure of the facilities listed above under the full CCR Rule would require studies for Location Restrictions, Design Criteria, Operating Criteria, and Groundwater Monitoring. Based on discussions with engineering companies, it is anticipated that Location Restrictions, Design

Criteria, and Operating Criteria studies would cost between $100k and $250k per facility. Groundwater Monitoring for the Green River is estimated at $250k to $350k for the design and construction of the groundwater monitoring system that meets the CCR Rule's requirements. In addition to the studies listed above, the facility would have to undergo 30 years of post-closure care. Results of the studies listed above and the 30 years of post-closure care must be posted to a publically accessible website. If the facilities were to attain inactive status, they would be closed under State requirements; Groundwater Monitoring would be approximately ¼ to 1/3 the cost, the post-closure care is 5 years, and all information is submitted to the State. The main unknown is citizen lawsuits. Since the CCR Rule establishes minimum standards that must be followed, compliance with those standards are based on citizen suits. Since all information pertaining to a CCR facility must be posted to a publically accessible website, the information is readily available to the general public. Based on internal discussions, a citizen suit could cost between $2,000k to $5,000k per suit to defend and settle. If the CCR facility is closed under State requirements, a permit is issued for closure and enforcement is by the State.

Table 1 below shows a breakout of cost by location and project number for the current authorization request:

Table 1

Location	Project #	Conceptual Design ($000's)	Initial Construction ($000's)	Closure Construction ($000's)	Total ($000's)
LG&E	147098	$250			**$250**
KU	147099	$250			**$250**
E.W. Brown	147965	$750	-	-	**$750**
Ghent	147966	$750		-	**$750**
Green River	147967	$750	$2,500	-	**$3,250**
Pineville	147968	$625	-	-	**$625**
Tyrone	147969	$625	-	-	**$625**
Cane Run	147970	-	-	$500	**$500**
Mill Creek	147971	$750	-	-	**$750**
Trimble Co. (LGE)	147972	$390	-	-	**$390**
Trimble Co. (KU)	147973	$360	-	-	**$360**
Totals		**$5,500**	**$2,500**	**$500**	**$8,500**

Table 2 below shows estimated cash flows for the current authorization request:

Table 2

Estimated Cash Flows ($000's)			
Task	**2015**	**2016**	**Total**
Engineering	$500		**$500**
Development & Conceptual Design	$1,342	$3,658	**$5,000**
Inactive Construction Activities	$2,500	-	**$2,500**
Cane Run Final Closure	-	$500	**$500**
Totals	**$4,342**	**$4,158**	**$8,500**

Table 3 below shows the 2015 Business Plan closure costs broken out by year (net):

Table 3

2015 Business Plan ($000's)								
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
CCR Ruling	$403	$3,565	$105,508	$76,836	$86,040	$120,222	$129,629	**$522,898**
Totals	**$403**	**$3,565**	**$105,508**	**$76,836**	**$86,040**	**$120,222**	**$129,629**	**522,898**

The amounts incurred through the first quarter of 2016 will be recorded as non-mechanism and moved to mechanism when the project receives ECR approval, currently anticipated for the second quarter of 2016.

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	Pre-2015	2015	2016	Post 2016	Total
1. Capital Investment Proposed	-	-	-	-	-
2. Cost of Removal Proposed	-	4,342	4,158	-	8,500
3. Total Capital and Removal Proposed (1+2)	-	4,342	4,158	-	8,500
4. Capital Investment 2015 BP	-	-	-	2,616	2,616
5. Cost of Removal 2015 BP	403	3,565	105,508	410,806	520,282
6. Total Capital and Removal 2015 BP (4+5)	403	3,565	105,508	413,422	522,898
7. Capital Investment variance to BP (4-1)	-	-	-	2,616	2,616
8. Cost of Removal variance to BP (5-2)	403	(777)	101,350	410,806	511,782
9. Total Capital and Removal variance to BP (6-3)	403	(777)	101,350	413,422	514,398

Financial Summary ($000s):

Below is the financial analysis for the project:

Financial Analysis - Project Summary ($000)	Project	2015	2016	2017	2018	2019	Life of Project
Project Net Income							
	147098	$ (3)	$ (5)	$ 10	$ 14	$ 12	$ 198
	147099	$ (3)	$ (5)	$ 10	$ 14	$ 12	$ 213
	147965	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 808
	147966	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 808
	147967	$ (23)	$ (38)	$ 141	$ 177	$ 177	$ 3,491
	147968	$ (3)	$ (7)	$ 27	$ 34	$ 29	$ 622
	147969	$ (3)	$ (7)	$ 27	$ 34	$ 34	$ 672
	147970	$ -	$ (10)	$ 20	$ 27	$ 25	$ 402
	147971	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 762
	147972	$ (2)	$ (5)	$ 17	$ 21	$ 21	$ 396
	147973	$ (2)	$ (4)	$ 16	$ 20	$ 20	$ 387
Project ROE							
	147098	-4.4%	-3.8%	7.9%	11.2%	10.8%	9.8%
	147099	-4.4%	-3.7%	7.9%	11.2%	10.8%	9.9%
	147965	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.4%
	147966	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.4%
	147967	-4.4%	-2.7%	8.2%	10.3%	10.3%	10.2%
	147968	-4.4%	-3.0%	8.2%	10.3%	8.9%	10.1%
	147969	-4.4%	-3.0%	8.2%	10.3%	10.3%	10.3%
	147970	0.0%	-7.8%	7.9%	11.2%	10.8%	10.6%
	147971	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.3%
	147972	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.3%
	147973	-4.4%	-3.0%	8.2%	10.3%	10.3%	10.3%

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	N
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N
#6	Does the project increase the emissions unit's electrical output (gross MW)?	N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	N
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	N

Conclusions and Recommendation

It is recommended that this Authorized Investment Proposal be approved in the amount of $8,500k to perform overall Project Development/Conceptual Engineering, and Initial Construction at Cane Run, and Green River for the EPA's CCR Rule – Impoundment Closure projects. Sanction request for the remaining project spend may be made in late 2015 in conjunction with the KPSC ECR filing.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: September 29, 2020

Project Name: Ghent Dry Sorbent Injection (DSI) Balancing and Cobra Lances

Total Capital Expenditures: $7,886k (Including $675k of contingency)

Total O&M: $0

Project Number(s): 157591

Business Unit/Line of Business: Project Engineering (PE)

Prepared/Presented By: Jeffrey B. Heun

Brief Description of Project

During the March 30, 2016 Investment Committee (IC) meeting, the IC approved the Ghent Dry Sorbent Injection (DSI) System Improvements for $4,000k (*Attachment #1*). The scope of work was to modify the Units 1, 3, and 4 DSI system to address flow distribution issue between each unit's two (2) flue gas ducts. The initial concept was to utilize a design similar to the Unit 2 system which had a blower for each injection point which allowed for proper balancing of the DSI flows between the flue gas ducts. The work was approved in the 2011 ECR Plan and included in the 2016 BP.

Upon completion of the Pulse Jet Fabric Filter (PJFF) projects, DSI consumption was evaluated on Units 1, 3, and 4 and a determination was made that the consumption was higher than expected when compared to similar sized generation units equipped with similar pollution control equipment due to the imbalance from one duct to another on each unit, as well as injection lance designs. As a result of this evaluation, the Company (Plant and PE) reviewed multiple options that addressed the flow distribution and ultimately determined that modifying the Unit 1, 3, and 4 DSI system to have one blower for each injection location was the best option.

Why is the project needed? What if we do nothing?

Modification to the Units 1, 3, and 4 DSI systems will significantly reduce DSI consumption as well as the daily maintenance activities associated with having to unplug the existing injection lances. The current configuration of the DSI system is not balanced between each unit's two (2) flue gas ducts. As a result of the unbalanced configuration, DSI is over injected into the flue gas stream to ensure both ducts achieve the required SO_3 reduction. In addition to flue gas flow imbalance, the current configuration of the conveying system biases the DSI flow to the ducts based on least path of resistance caused by injection lance pluggage. To ensure that both ducts receive an adequate flow of DSI to meet SO_3 limits, the overall DSI flow has to be increased.

In an effort to address pluggage of the injection lances and address the flow bias between the two ducts, the injection lances are cleaned at least once per shift. This maintenance activity helps but does not eliminate the lances from plugging. At the same time, the flow biases result in increased DSI flow though the lances above their normal operation which increases the rate of lance plugging.

If no action is taken to address the unbalanced flows and plugging of the injection lances, DSI consumption will remain higher than optimized and additional ongoing maintenance will be required resulting in higher O&M costs.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre 2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	12	2,250	5,625	-	7,886
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	12	2,250	5,625	-	7,886
4. Capital Investment 2020 BP	3,078	2,838	-	-	5,916
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	3,078	2,838	-	-	5,916
7. Capital Investment variance to BP (4-1)	3,067	588	(5,625)	-	(1,970)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	3,067	588	(5,625)	-	(1,970)

PE is requesting $675k in program management contingency which is ten percent (10%) of the construction contract. As a result of the project, an O&M savings of $1,100k per year compared to the 2020 BP should be realized, which is based on a reduction of two (2) resident contractors and 15% reduction in DSI consumption. As a result of the improved DSI distribution in the DSI delivery system and reduced pluggage, the Plant has determined that a reduction of two (2) resident maintenance contractors is appropriate. Based on current and ongoing flow modeling by United Conveyor Corporation (UCC), UCC has indicated the Plant will see at least a 15% reduction in DSI consumption. This request is based on achieving the minimum predicted savings.

Risks

- If no action is taken to address the unbalanced flows and injection lances, the Plants DSI consumption will be higher and additional ongoing maintenance will be required resulting in higher O&M costs.
- Unit outages will be required to perform the flowing balancing work as well as the installation of the cobra lances. The Plant and PE will work together with the contractor to ensure adequate time and access is available to perform the work during the upcoming 2021 outages at Ghent.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $7,716
    - Reduction of two (2) resident maintenance contractors
    - A 15% reduction in DSI consumption
    - CEM depreciation life – 2037
2. Alternative #1 – Do Nothing: NPVRR: ($000s) $8,519

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Ghent Dry Sorbent Injection Balancing and Cobra Lances project for $7,886k to reduce DSI consumption and Plant O&M costs.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Revised Project and Contract Proposal for Investment Committee Meeting on: March 30, 2016

Contract:

Contract Name: Ghent Environmental Air Compliance – Engineering, Procurement, and Construction Agreement – [redacted]

Revised Contract Authorization: $577,100k (including 1.8% forward contingency)

September 2015 Contract Authorization: $573,100k

Original Contract Authorization: $501,400k

Project:

Project Name: Ghent Environmental Air Compliance

Revised Ghent Environmental Air Compliance Project Total Seeking IC Approval: $667,750k

May 2015 Ghent Environmental Air Compliance Project Total Project Sanction: $656,750k

Business Unit/Line of Business: Project Engineering

Prepared/Presented by: Doug Schetzel and Scott Straight

Executive Summary

This proposal seeks a revised Ghent Environmental Air Compliance (GEAC) Project authorization of $672,750k, an increase of $16,000k from the May 2015 authorization. The sanction increase is necessary to complete demolition of the Ghent (GH) Unit 2 Electrostatic Precipitators (ESP), to design and install improvements to the GH Unit 1, 3 & 4 Dry Sorbent Injection Systems (DSI), and either to stabilize the partially demolished Unit 1 ESP or demolish similar to Unit 2. The 2016 BP contains $4,000k for the GH Unit 1 and Unit 2 ESP Demolition project and $4,000k for the DSI System Improvement projects. Please see Table 1 below which reflects the breakdown of the requested authorization increase from the May 2015 authorization:

Table 1

GEAC Project Authorization Request ($000s)	Requested Sanction	2016 BP Amount	Variance to 2016 BP
GH 2 ESP Demolition	$6,500	$2,000	$4,500
GH 1 ESP Stabilization (Option 1)	$500	$0	$500
GH 1 ESP Demolition (Option 2)	$5,500	$2,000	$3,500
GH DSI Improvements	$4,000	$4,000	$0

This proposal also seeks to increase the September 2015 authorization of the GEAC Engineering, Procurement and Construction (EPC) contract with [redacted] by $9,000k. The increased authorization will allow for some or all of the non-EPC demolition cost on the Unit 1 and Unit 2's ESP be moved int[redacted] scope of work. The requested amount for the [redacted] contract is $5,000k greater than the 2016 BP amount to allow some or all the ESP demolition scope to be performed by [redacted] under the EPC Agreement. The new sanction is $38,250k less than the 2011 Environmental Cost Recoverable (ECR) filing amount.

Background

- **Ghent DSI System Improvements**

The design of the DSI systems at Ghent has evolved during the course of the project. The last system installed on GH Unit 2 has dedicated piping and a blower for each injection point. This allows proper balancing of the DSI flows to assure proper SO_3 control, as well as significant improvement in DSI utilization which reduces cost with a very short payback on this investment. The concentration of SO_3 must be less than 5 parts per million (ppm) for optimum mercury (Hg) in the Pulse Jet Fabric Filter (PJFF) and to limit downstream gas path corrosion. The DSI systems on GH Units 1, 3 & 4 will be modified to a design similar to GH Unit 2. This modification is being considered for the Mill Creek Units 3&4 and Trimble County Unit 1 baghouses that also have an A and B baghouses serving individual units. The requested authorization to spend $4,000k on GH DSI improvements is contained in the 2016 BP.

- **Ghent ESP Demolition Background**

When the GH Unit 1 & 2 Pulse Jet Fabric Filters (PJFF) were placed in service, the GH Unit 1 & 2 ESPs were abandoned in place. The footprint around GH Unit 1 & 2 is very constrained and the demolition of the GH Unit 1 & 2 ESPs is necessary to improve access to the units. The GH Unit 2 PJFF is located in what was the GH 1& 2 courtyard. Demolition of the GH Unit 2 ESP will restore some of the open space around the units necessary for maintenance and outage laydown areas. The last project sanction included $3,000k for general demolition of GH Unit 1 & 2. Those funds were used to remove GH Unit 1 ESP duct to allow for the placement of a crane to construct the Unit 2 PJFF and to begin demolition of the GH Unit 2 ESP. The decision to use a majority of the budgeted demolition funds to allow crane access for Unit 2's PJFF was attributed to the significant savings of the Unit 2 PJFF and the shorter tie-in outage duration. These significant benefits resulted in greater savings and execution risk to the project than the incremental cost of demolition. An additional savings was realized by starting the GH Unit 2 ESP demolition when the Unit 2 PJFF was finished by utilizing the large outage crane used to construct the GH Unit 2 PJFF to be utilized to begin demolition of the Unit 2 ESP, saving approximately $500k in crane mobilization and demobilization costs. The attached sketch shows the area around the GH Unit 1 and 2 ESPs. Demolition of the GH Unit 2 ESP provides most of increase in useable footprint (Attachment 1 & 2).

- **Ghent Unit 2 ESP Demolition**

The estimated remaining cost to demolish the GH Unit 2 ESP is approximately $6,500k. The 2016 BP has $4,000k for Ghent ESP Demolition, representing a $2,500k increase over the 2016 BP.

- **Ghent Unit 1 – Option 1 (ESP Stabilization)**

Since the ducting to the GH Unit 1 ESP was removed to allow more efficient construction of the GH Unit 2 PJFF, the GH Unit 1 ESP can be stabilized by removing as much ash as possible and closing the duct openings and other penetrations to the ESP and the GH Unit 1 structure. The estimated cost to stabilize the GH Unit 1 ESP is $500k. The requested authorization of $500k to stabilize the GH Unit 1 ESP is incremental to the 2016 BP. It should be noted that this spend does not avoid the eventual need to demolish the ESP, but merely defers the expense. As with any flue gas related equipment, "mothballing" the ESP will eventually result in it corroding away and becoming a safety hazard over the next 5-15 years. It will then require demolition.

- **Ghent Unit 1 – Option 2 (ESP Demolition)**

The estimated cost to demolish the GH Unit 1 ESP is approximately $5,500k. The GH Unit 1 ESP footprint is mostly under the Selective Catalytic Reduction (SCR), thus minimal usable foot print is achieved. As stated in Option 1, demolition of the GH Unit 1 ESP will still be needed within 5-15 years, since any ash residue exposed to ambient moisture will corrode the ESP structure. If this option is chosen, the requested authorization of $5,500k would be $5,500k over the 2016 BP amount but this authorization would be in place of the authorization of the GH Unit 1 ESP stabilization.

Economic Analysis and Risks

- **Financial Summary**

Table 2 reflects the history of all Ghent Air Compliance project scopes that were part of the 2011 ECR filing.

Table 2:

($000)	ECR Filing	AIP	2012 MTP	2013 BP	2014 BP	2015 BP	2016 BP	Current Forecast
Ghent EAC	$711,000	$519,340	$692,000	$532,000	$599,000	$650,700	$664,750	$672,750

Table 3 gives a summary of total project spend and shows actual spend through January 2016 and projected costs through the completion of the project.

Table 3:

Summary of Total Project Spend ($000)	
Actual Costs:	
SAM Mitigation	$ 12,700
PJFF pre-2016	$ 630,116
PJFF January 2016	$ 1,704
Actual Costs through January 2016	$ 644,520
Projected Costs:	
February - Completion 2016	$ 25,409
Contingency 2016	$ 2,821
Projected Costs to completion	$ 28,230
Total Project Spend	**$ 672,750**

Table 4 lists the budget breakout that supports the current forecast using the Ghent Unit 1 – Option 2 (ESP Demolition) above vs the 2016 Business Plan (BP). The overage for 2016 was a carryover of funds from 2015 as well as any additional overages, will be funded through the RAC process by other Project Engineering projects.

Table 4:

Financial Detail by Year - Capital ($000s) (includes Ghent SAM projects)	**Pre 2016**	**2016**	**Total**
1. Capital Investment Proposed	634,736	14,652	649,388
2. Cost of Removal Proposed	7,820	15,541	23,361
3. Total Capital and Removal Proposed (1+2)	642,556	30,194	672,750
4. Capital Investment 2016 BP	640,993	10,669	651,662
5. Cost of Removal 2016 BP	8,088	5,000	13,088
6. Total Capital and Removal 2016 BP (4+5)	649,081	15,669	664,750
7. Capital Investment variance to BP (4-1)	6,257	(3,983)	2,274
8. Cost of Removal variance to BP (5-2)	268	(10,541)	(10,273)
9. Total Capital and Removal variance to BP (6-3)	6,525	(14,525)	(8,000)

Alternative Option: Delayed Demolition of GH1 ESP

Alternatively, if it is not desired to demolish the Ghent Unit 1 Electrostatic Precipitator for $5,500k, authorization for the Ghent Environmental Air Compliance Project could be increased by $11,000k to $667,750k and the authorization for the Ghent Environmental Air Compliance Engineering, Procurement, and Construction Agreement with [redacted] could be increased $4,000k to $577,100k. This authorization allows the Ghent Dry Sorbent Injection System Improvements for $4,000k, the demolition of the Ghent Unit 2 Electrostatic Precipitator for $6,500k and the stabilization of the Ghent Unit 1 Electrostatic Precipitator for $500k. The Ghent Unit 1 Electrostatic Precipitator will still need to be demolished at a later date.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the $11,000k increase of the Ghent Environmental Air Compliance Project total authorization to $667,750k and the $4,000k increase of the Ghent Environmental Air Compliance Engineering, Procurement, and Construction Agreement with [redacted] to $577,100k. This authorization allows the Ghent Dry Sorbent Injection System Improvements for $4,000k, the Stabilization of the Ghent Unit 1 Electrostatic Precipitator for $500k and Demolition of the Ghent Unit 2 Electrostatic Precipitator for $6,500k.

The Investment Committee approved the Alternative Option: Delayed Demolition of GH1 ESP. Further analysis will be completed regarding the optimal timeframe for the demolition of the Ghent Unit 1 Electrostatic Precipitator. Results of this analysis will be distributed for discussion.

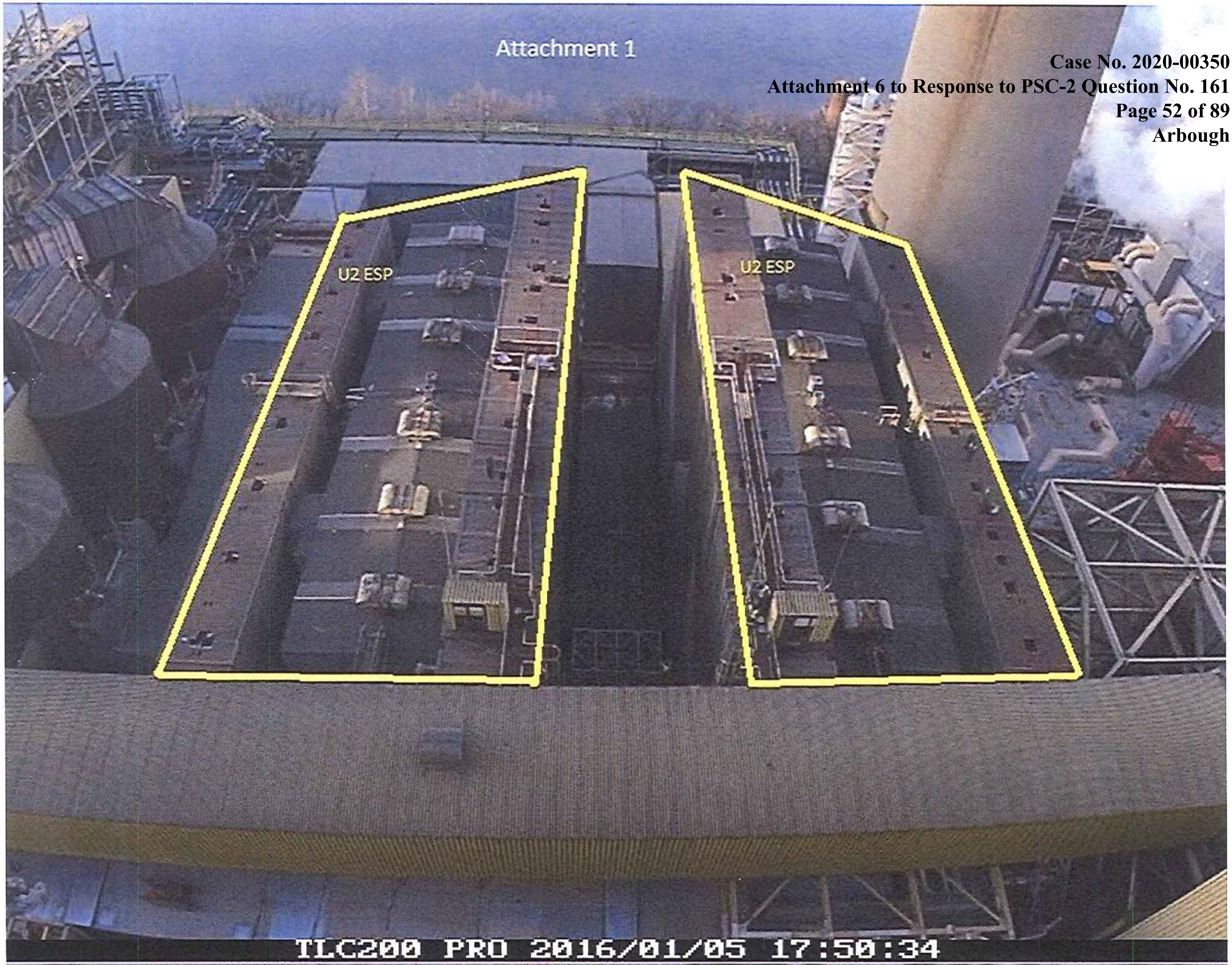
Douglas Schetzel 4/4/2016	Anthony L. Ruckriegel 4/5/2016
Douglas K. Schetzel Dir. Business Development/Mgr. Major Capital Projects	Anthony L. Ruckriegel Mgr. Contracts/Major Capital Project

4/5/16	DUA for J. Voyles 4/5/16
R. Scott Straight Dir. Project Engineering	John N. Voyles VP Transmission & Generation Services

4/5/16	KtW Blake 4/6/16
Paul W. Thompson Chief Operating Officer	Kent W. Blake Chief Financial Officer

4/7/16

Victor A. Staffieri
Chief Executive Officer


Attachment 1
U2 ESP
U2 ESP
TLC200 PRO 2016/01/05 17:50:34


Attachment 2
U1 SCR
U1 ESP

Jacobs, John

From:	Allgeier, Lana
Sent:	Friday, April 08, 2016 9:10 AM
To:	Jacobs, John
Subject:	FW: Delegation Of Authority Notification For JOHN VOYLES to SCOTT STRAIGHT

From: LG&E ERS Website
Sent: Friday, April 01, 2016 3:20 PM
To: Delegation of Authority <doa@lge-ku.com>; Saunders, Eileen <Eileen.Saunders@lge-ku.com>; Mattingly, Jennifer <Jennifer.Mattingly@lge-ku.com>; Voyles, John <John.Voyles@lge-ku.com>; Thompson, Paul <Paul.Thompson@lge-ku.com>; Straight, Scott <Scott.Straight@lge-ku.com>; Jessee, Tom <Tom.Jessee@lge-ku.com>; Oracle Security <oracle@lge-ku.com>; Cash Management <Cash@lge-ku.com>; Hance, Chuck <Chuck.Hance@lge-ku.com>; Singery, Debbie <Debbie.Singery@lge-ku.com>; Lipp, Joan <Joan.Lipp@lge-ku.com>; Disney, Judy <Judy.Disney@lge-ku.com>; Ruckriegel, Tony <Tony.Ruckriegel@lge-ku.com>; Burns, Kyle <Kyle.Burns@lge-ku.com>; Mooney, Lisa <Lisa.Mooney@lge-ku.com>; Heun, Jeff <Jeff.Heun@lge-ku.com>; Imber, Philip <Philip.Imber@lge-ku.com>; Allgeier, Lana <Lana.Allgeier@lge-ku.com>; Wilson, Dan <Dan.Wilson@lge-ku.com>; Schetzel, Doug <Doug.Schetzel@lge-ku.com>; Ware, Dianne <DIANNE.WARE@lge-ku.com>
Subject: Delegation Of Authority Notification For JOHN VOYLES to SCOTT STRAIGHT

This delegation of authority is effective with the start of the work day 4/4/2016 through the end of the work day 4/8/2016.
The Reason for this delegation of authority is Vacation.

Delegation of Authority for		Authority being delegated to	
Name	JOHN VOYLES	**Name**	SCOTT STRAIGHT
Location	LG&E Center 14th floor	**Location**	Broadway Office Complex-3
Department	VP-Transmission/Generation Svc	**Department**	Project Engineering
Company	LG&E and KU Services Company	**Company**	LG&E and KU Services Company
Phone	502/627-4762	**Phone**	502/627-2701
E-Mail	JOHN.VOYLES@LGE-KU.COM	**E-Mail**	SCOTT.STRAIGHT@LGE-KU.COM
Cell Phone	N/A	**Cell Phone**	N/A
Pager	N/A	**Pager**	N/A

Comments :

Investment Proposal for Investment Committee Meeting: November 20, 2020

Project Name: Trimble County CCR Project (Landfill) - Additional Buffer Property Acquisition 2020

Total Capital Expenditures: $1,600k (gross), $1,200k (net)[1]

Project Number(s): TC Landfill will provide funding (151119 / 151123) via projects: 163984 / 163985 (LGE/KU)

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Joan S. Lipp / R. Scott Straight

Description of Project

Authority is being requested to purchase two adjacent properties to the Trimble County Coal Combustion Residual (CCR) Landfill from the Leach families for a total of $1,600k (gross) or $1,200k (net). No contingency is being sought. These properties have been included in a past IC authorization request and are being purchased to:

- provide additional property buffers between local residents and the landfill area, and
- allow local residents to relocate away from the landfill area.

Previous adjacent property purchase IC Papers:

- **August 2012** Trimble County CCR Project, Additional Property Acquisition: 17 named parcels (see Attachment #1). The two parcels included in this paper were part of the original listing.
- **March 2016** Trimble County Landfill Phase 1A Project: Updated funding amount for remaining parcels not purchased per the August 2012 IC Paper (see Attachment #2 Appendix D).

This authorization request includes: a) the purchase of two parcels totaling 153 acres (closing is planned to be completed by December 2020) from the Leach families, and b) removal of residential buildings and structures in the Spring of 2021. As stated above, the land will be used as a buffer between the landfill and adjacent landowners. Funding was approved per August 2012 and March 2016 IC papers and is in accordance with LG&E and KU's ("Companies") Quarterly KPSC ECR project reports that have continuously stated that the Companies continue to acquire properties adjacent to the landfill to allow buffer from the remaining neighbors and allow an opportunity for those adjacent to relocate. The property purchase prices are 152% of appraisal which is in the range of prices paid for other surrounding properties.

Budget Comparison & Financial Summary

[1] Co-Owners of the Trimble County plant: Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA) are responsible for 25%. IMEA owns 12.12% and IMPA owns 12.88%.

Financial Detail by Year - Capital ($000s) (Net)	2020	2021	2022	Total
1. Capital Investment Proposed (Net)	1,050	150	-	1,200
2. Cost of Removal Proposed (Net)	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,050	150	-	1,200
4. Capital Investment 2021 BP (Net)	1,050	150	-	1,200
5. Cost of Removal 2021 BP (Net)	-	-	-	-
6. Total Capital and Removal Proposed (Net) (4+5)	1,050	150	-	1,200
7. Capital Investment variance to BP (4-1)	-	-	-	-

Risks

No additional risks were identified if the properties are not purchased beyond the current risk of having adjacent land owners to the landfill daily operation.

Alternatives Considered

1. Recommendation: Purchase of property NPVRR: (000s) $1,874 (net)
   Purchase of the property is consistent with other purchases of adjacent property.

2. Alternative #1: Do Nothing NPVRR: (000s)

Conclusions and Recommendation

It is recommended that the Investment Committee approve the purchase of two adjacent properties for the Trimble County Coal Combustion Residual (CCR) Landfill for $1,600k (gross) or $1,200k (net) to provide additional buffer around the landfill.

Approval Confirmation for Land Purchase Greater Than $500,000:

The Capital property purchase spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital property purchase spending request.

Kent W. Blake
Chief Financial Officer

Paul W. Thompson
President and Chief Operating Officer

Contract Proposal for Investment Committee Meeting on: **E-Mail Vote**

Contract Name: **Trimble County CCR Project, Additional Property Acquisition**

Contract Total Seeking IC Approval **$ 5,190 k (gross) and $ 3,893 k (net)**
Total Contract Expenditures: **$ 5,190 k (gross) and $ 3,893 k (net)**

Business Unit/Line of Business: **Generation Services/Project Engineering**
Prepared/Presented By: **Robert C. Waterman, Ronald D. Gregory**

Executive Summary

Authority is being requested to procure adjacent properties for the Trimble County Coal Combustion Residual (CCR) Landfill Project for $5.190 million (gross) or $3.893 million (net). No contingency is being sought. These properties are necessary to:

- provide additional soil borrow areas and reduce stream and wetland impacts to the Ravine B watershed
- provide additional property buffers between local residents and the landfill
- optimize the landfill and view shed designs
- provide additional landfill cover for use during operation
- eliminate the potential for Reverse Condemnation Litigation
- reduce complaints during construction and operation of the landfill

This request is being made due to the original sanction of the landfill not including the purchase of land. Permitting activities to date have resulted in the United States Army Corps of Engineers (USACE), Kentucky Division of Water (DOW), and the United States Environmental Protection Agency (EPA) commenting on the amount of streams planned to be "taken" in the development of the new landfill, including the affected land used for borrow material. This addition of scope to purchase land provides the benefits listed above and reduces the amount of stream taking for the development and maintenance of the new landfill.

Background

In 2005, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU) began a fleet-wide study of all coal combustion residual (CCR) storage facilities. CCR materials are the byproducts of burning coal and include the follow materials: bottom ash, pyrites, fly ash, and gypsum. The Trimble County Generating Station was identified as one of the stations requiring additional CCR storage.

Engineering on the new CCR storage plan for Trimble County began in 2005 and continues to the present. The CCR plan was divided into two stages:

- Stage I: Bottom Ash Pond Dike Extension and Gypsum Storage Pond Liner Project (TC BAP/GSP Project)

- Stage II: Landfill Project

Stage I---TC BAP/GSP Project

This scope provided for incremental storage for CCR materials while the Stage II CCR Project (Landfill) is being designed, permitted, and constructed. Construction of the TC BAP/GSP Project began in June, 2009, and was completed in December, 2011. Both BAP and GSP are now in service.

Stage II---Landfill Project

During the construction of Unit 1, LG&E purchased properties northeast of the power block and contiguous to properties containing the power block. This new property included three ravines, designated as A, B, and C, and was approximately 1,000 acres. The property is located on the east side of Kentucky State Road 1838. LG&E purchased this property for the development of future CCR storage. However, the land was never utilized until now.

Simultaneous to the design and construction of the BAP/GSP Project, design and permitting began on the CCR landfill. The Detailed Design for the Landfill is substantially completed and includes the development of approximately 220 acres for the new landfill in Ravine B only. Ravine B is bounded on the north by Wentworth Road and on the south by Ogden Ridge Road. Ravines A or C will not be utilized for CCR storage.

Various permits are necessary for the landfill. Below is a description as well as a status on each of the permit:

- DOW 401 Permit. This permit was filed in December, 2010. The permit application is pending, except as noted. The DOW Permit has the following components:
  - Flood Plain Permit. This portion of the permit was received in July, 2012.
  - Water Quality Permit (stream and wetland impacts)
  - Dam Safety Permit (embankments for Sediment Pond and Leachate Collection Pond). The permit application will be submitted in August.

- Kentucky Division of Waste Management (DWM). The DWM Permit was filed in May, 2011. DWM has issued Notice of Deficiencies (NOD) #1 and #2. A response for NOD #1 has been completed. The response to NOD #2 is currently being developed and will be submitted in August. Additional NODs are anticipated based upon experience on similar landfill projects. This permit is also pending.

- USACE 404 Permit. The permit was filed in December, 2010 and is pending. USACE has requested the following additional items:

  - A supplement to the previously submitted Alternative Analysis, which is currently being developed, including a review of the location of borrow areas.
  - A review of the karst feature known as “Lime Cave” or “Wentworth Cave” relative to the Civil War Underground Railroad. A consultant from Berea College recommended by the USACE has been retained to perform this consultation.
  - A review of the View Shed issues relative to a local structure deemed as eligible for listing on the National Register of Historic Places. (Section 106).

Originally, property acquisition for the Trimble County CCR Landfill was not required, since the properties had already been obtained. However, due to permitting changes and other issues, property acquisition should now be considered for the following reasons:

1. **<u>Borrow Areas and Associated 401 and 404 Permitting Issues</u>**. The development of the Trimble County Landfill may now require additional borrow materials, including top soil, clay, and blasted rock to provide for the following:

- Clay subbase for the lined landfill
- Structural fill

- Aesthetic berms for shielding the view of the landfill from adjacent neighbors
- Other future soil borrow needs

As part of the USACE 404 Permit, a meeting was held at the Trimble County site in December, 2011, to review the pending permit. Representatives from the EPA and DOW personnel were also present.

At this meeting, these regulatory agencies indicated that the stream and wetland impacts being proposed by LG&E were excessive. As a result of this meeting, LG&E reduced the impacts by removing all of the proposed borrow areas from the upper terraces of Ravine A. (The Landfill is being built within Ravine B, which is located immediately to the south of Ravine A).

LG&E was also requested to revise the Alternative Analysis contained in the 404 Permit. In this revised analysis, the USACE has requested an additional analysis of alternative borrow sites, since 24% of the stream and wetland impacts in the permits are due to stream and wetland impacts in the borrow sites.

By purchasing these proposed properties, additional borrow sites will become available, outside of the existing permit boundaries. LG&E will be able to demonstrate to the USACE and EPA that the streams and wetland impacts in Ravine B have been further minimized. This would reduce one of the USACE and EPA objections to the pending 404 Permit.

2. **Borrow Areas and Associated DWM Permitting Issues**. In addition, when the DWM issues the landfill permit, various permit conditions will be included. Many of these conditions exist to protect adjacent property owners. If LG&E obtains additional properties, some of the permit conditions may be mitigated or eliminated.

3. **Optimization of Borrow Areas for Landfill Construction**. The additional properties will also allow the Trimble County Landfill Design Engineer to optimize the borrow areas, which may result in project cost reductions.

4. **Future Landfill Cover for Operations**. In addition to the borrow areas required to meet the requirements of the construction of the landfill, borrow materials are also required for landfill cover during operation of the landfill. As CCR materials are placed in the landfill during operation, the exposed or "open" faces must be periodically covered with a suitable soil cover. This cover prevents fugitive dust from the CCR materials (bottom ash, pyrites, fly ash and gypsum). Also, the cover reduces water from penetrating into the core of the landfill.

   The landfill cover materials will require soil borrow areas, which have the same issues as with the USACE's permitting as indicated above.

   Without this landfill cover material being available near the landfill, it will be necessary to truck the landfill cover from off-site at a considerable operating expense, similar to what has been experienced at other LG&E landfills.

5. **Additional Buffer beyond Statutory Requirements**. The current landfill design includes provisions for buffer as required by Kentucky statutes for special waste landfills within the properties owned by LG&E. These newly procured properties will provide additional buffer, over and above what is required by statute. This additional buffer is deemed a prudent mechanism to reduce or eliminate future neighbor complaints due to noise, dust, and other issues during the operation of the landfill.

6. **Reduces Potential of Reverse Condemnation Litigation and Community Goodwill**. Adjacent property owners to the proposed landfill may litigate for reduced property value due to the construction and operation of the adjacent landfill, a process known as "Reverse Condemnation."

   In these cases, where the landowner prevails, LG&E would be forced to pay the difference between the land value before landfill development/operation and the land value after landfill development. In these cases where judgment is granted against LG&E, costs would be expended for which LG&E receives no value.

If the properties are purchased before Reverse Condemnation, then this issue is eliminated and LG&E has additional properties to show for the costs.

In most cases, where properties are being considered for purchase, the property owner approached LG&E with a desire to sell. By buying these properties, it gives the property owner an opportunity to relocate to another location, thereby eliminating their objections to the landfill.

7. **<u>Optimize View Shed Design</u>**. A requirement of the landfill design is the construction of aesthetic berms and other means to "hide" the view of the landfill from the public. This is commonly known as "view shed." By obtaining these adjacent properties, the view shed design can be optimized, and in some cases, may be reduced or eliminated altogether.

   One property in particular, the Stansbury property, has been evaluated and may be eligible for listing on the National Register of Historic Places. Special view shed considerations will need to be included in the design due to this potential designation.

8. **<u>Optimize Surface Drainage Design</u>**. Directing rain water around the perimeter of the landfill is a significant part of the Detailed Design of the landfill. By obtaining these adjacent properties, the rain fall diversion ditch design will be optimized. This optimization may create more space available for CCR storage.

Project Description

Authority is being sought to procure additional properties contiguous to the proposed Trimble County Generating Station landfill. All of these properties are either on Ogden Ridge Road or Wentworth Road. The potential purchase includes up to seventeen (17) parcels for a total of approximately 480 acres.

All the properties are either on the east or south sides of the landfill. Ravine A is located on the north side of the landfill and LG&E owns all the property on the west side. See Appendix I (project drawing TC0-C02418 Revision A) which shows the proposed properties relative to the landfill. The proposed properties are REDACTED.

The property acquisition will be part of the Trimble County CCR Landfill Project. This project's initial phase was approved for $79,720 k (net) or $ 106,293 (gross) at the Investment Meeting on October 15, 2009 (Project Numbers 127135 and 127134). See Appendix II for the Original Investment Proposal. This original proposal included the following:

- Engineering for the landfill development and CCR Treatment/Transportation
- Permitting, and
- Construction of Phase I of the Landfill

The Trimble County CCR Landfill Project has received Environmental Cost Recovery (ECR) approval in June 2009 as well as approval from the Kentucky Public Service Commission.

Economic Analysis and Risks

Authority is being requested for $5.190 million (gross) or $3.893 million (net) for the purpose of procuring adjacent properties to the proposed Trimble County Generating Station CCR Landfill. This Property Acquisition has been included in the proposed 2013 Business Plan. The Property Acquisition Cash Flows by year are estimated as follows:

2012	$ 1.223 million (gross)	$ 0.918 million (net)
2013	$ 1.271 million (gross)	$ 0.953 million (net)
2014	$ 1.322 million (gross)	$ 0.992 million (net)
2015	<u>$ 1.374 million</u> (gross)	<u>$ 1.030 million (net)</u>
	$ 5.190 million (gross)	$ 3.893 million (net)

Attached Appendix III shows the details for the property acquisition estimate.

No contingency has been included.

The above amount for property acquisition can be absorbed in the existing authority. However, at a later date, additional authority will be sought for the latter phases of the project due the following:

- Increased Landfill construction cost due to changes from the Final Conceptual to the Detailed Design,
- Increased CCR Treatment and Transportation infrastructure estimate due to changes from the Initial Conceptual Design to the Final Conceptual Design

- **Risk of Project**

  The risks associated with this project are only associated with a "do-nothing" approach, which has the following risks:
    - Reduces stream and wetland impacts to the Ravine B water shed
    - Provides additional property buffers between local residents and the landfill
    - Optimizes the landfill and view shed designs
    - Provides additional landfill cover for use during operation
    - Eliminates the potential for Reverse Condemnation Litigation
    - Reduces complaints during construction and operation of the landfill

- **Other Alternatives Considered**

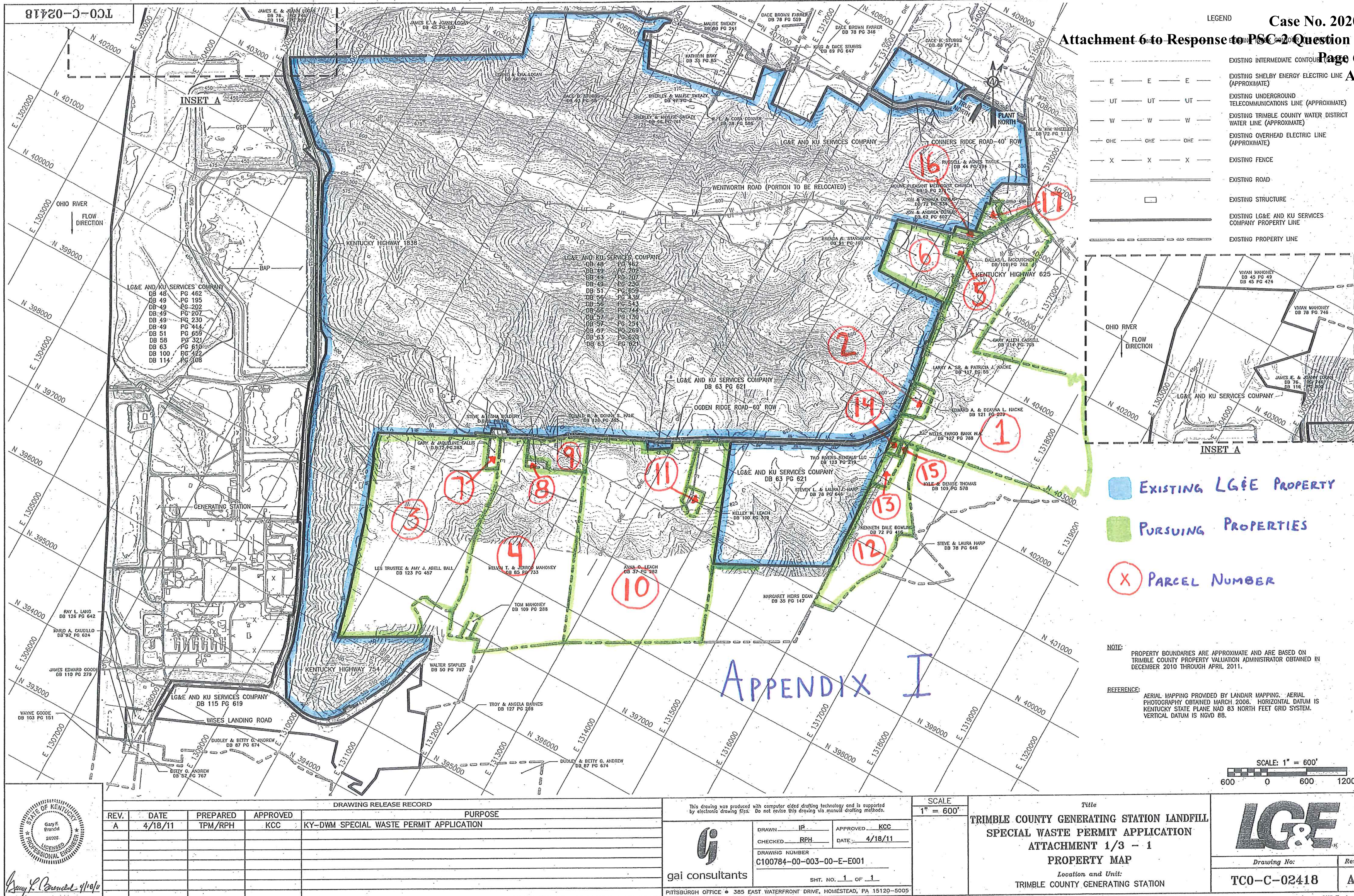
  The only Alternative is the "do-nothing" approach. The risks associated with this Alternative are discussed above.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the **Trimble County CCR Project, Additional Landfill Property Acquisition** project for **$ 5,190 k (gross) and $ 3,893 k (net)**.

Attachments

Appendix I:	Property Drawing TC0-C-02418 Revision A
Appendix II:	Original Investment Proposal dated October 15, 2009
Appendix III:	Cost Estimate


TCO-C-02418
INSET A
OHIO RIVER
FLOW DIRECTION
KENTUCKY HIGHWAY 1838
LG&E AND KU SERVICES COMPANY
DB 48 PG 462
DB 49 PG 195
DB 49 PG 202
DB 49 PG 207
DB 49 PG 230
DB 49 PG 414
DB 51 PG 659
DB 58 PG 321
DB 63 PG 610
DB 100 PG 422
DB 114 PG 108
GENERATING STATION
WENTWORTH ROAD (PORTION TO BE RELOCATED)
CONNERS RIDGE ROAD–40' ROW
OGDEN RIDGE ROAD–60' ROW
KENTUCKY HIGHWAY 625
KENTUCKY HIGHWAY 754
WISES LANDING ROAD
LG&E AND KU SERVICES COMPANY DB 63 PG 621
LG&E AND KU SERVICES COMPANY DB 115 PG 619
LES TRUSTEE & AMY J. ABELL BALL DB 123 PG 457
MELVIN T. & JERROD MAHONEY DB 85 PG 733
TOM MAHONEY DB 109 PG 265
ANNA C. LEACH DB 37 PG 282
KELLEY W. LEACH DB 100 PG 376
MARGARET HEIRS DEAN DB 35 PG 147
WALTER STAPLES DB 50 PG 797
TROY & ANGELA BARNES DB 127 PG 298
DUDLEY & BETTY G. ANDREW DB 87 PG 674
LEGEND
EXISTING INTERMEDIATE CONTOUR
EXISTING SHELBY ENERGY ELECTRIC LINE (APPROXIMATE)
EXISTING UNDERGROUND TELECOMMUNICATIONS LINE (APPROXIMATE)
EXISTING TRIMBLE COUNTY WATER DISTRICT WATER LINE (APPROXIMATE)
EXISTING OVERHEAD ELECTRIC LINE (APPROXIMATE)
EXISTING FENCE
EXISTING ROAD
EXISTING STRUCTURE
EXISTING LG&E AND KU SERVICES COMPANY PROPERTY LINE
EXISTING PROPERTY LINE
Existing LG&E Property
Pursuing Properties
Parcel Number
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Appendix I
NOTE: PROPERTY BOUNDARIES ARE APPROXIMATE AND ARE BASED ON TRIMBLE COUNTY PROPERTY VALUATION ADMINISTRATOR OBTAINED IN DECEMBER 2010 THROUGH APRIL 2011.
REFERENCE: AERIAL MAPPING PROVIDED BY LANDAIR MAPPING. AERIAL PHOTOGRAPHY OBTAINED MARCH 2006. HORIZONTAL DATUM IS KENTUCKY STATE PLANE NAD 83 NORTH FEET GRID SYSTEM. VERTICAL DATUM IS NGVD 88.
SCALE: 1" = 600'
DRAWING RELEASE RECORD
REV. A | DATE 4/18/11 | PREPARED TPM/RPH | APPROVED KCC | PURPOSE KY-DWM SPECIAL WASTE PERMIT APPLICATION
This drawing was produced with computer aided drafting technology and is supported by electronic drawing files. Do not revise this drawing via manual drafting methods.
gai consultants
DRAWN IP APPROVED KCC
CHECKED RPH DATE 4/18/11
DRAWING NUMBER C100784-00-003-00-E-E001
SHT. NO. 1 OF 1
PITTSBURGH OFFICE 385 EAST WATERFRONT DRIVE, HOMESTEAD, PA 15120-5005
SCALE 1" = 600'
TRIMBLE COUNTY GENERATING STATION LANDFILL SPECIAL WASTE PERMIT APPLICATION ATTACHMENT 1/3 – 1 PROPERTY MAP
Location and Unit: TRIMBLE COUNTY GENERATING STATION
LG&E
Drawing No: TCO-C-02418
Rev. A

[redacted]

[redacted]

[redacted]

Investment and Contract Proposal for Investment Committee Meeting on: March 30, 2016

Project Name: Trimble County Coal Combustion Residuals Project – Phase I
Contract Name: Trimble County Coal Combustion Residuals Treatment Project - Engineer, Procure, and Construct

Initial Project Total Approved: Phase I Sanction \$106.0m (Gross); \$79.0m (Net)[1]
Revised Project Total Seeking IC Approval: Phase I Sanction \$369.0m (Gross); \$276.0m (Net)[1]

Total Initial Contract Authorization: \$256.0m (≈ 5% contingency) Gross
Total Initial Contract Authorization: \$192.0m (≈ 5% contingency) Net[1]

Business Unit/Line of Business: Project Engineering
Prepared/Presented By: Joan Lipp and Scott Straight

Executive Summary

The Trimble County Coal Combustion Residuals (CCR) Project was originally approved by the Investment Committee on October 15, 2009 at a partial sanction for Phase I of \$79.7m (Net) and a total Project cost of \$228.0m (Net), which can be found in Appendix A. This authorization request seeks approval to increase the sanction to \$369.0m[2] (Gross), \$276.3m (net) to cover all major components of Phase I, *less the cost of constructing the landfill proper*. This request also seeks approval to award the Trimble County Coal Combustion Residual Treatment & Transport (CCRT) Engineering, Procurement, and Construction (EPC) contract to [redacted] for an initial award amount of \$225.0m (Gross), with a total contract authorization of \$256.0m[3] (Gross), \$192.0m (net) inclusive of a 5% contract management contingency. The 2016 BP for the scopes included in this sanction is \$338.0m (Gross), \$253.5m (net) compared to the request of \$368.7m (Gross), \$276.5m (net). This variance of \$23.0m (net) is an increase of 9.1 percent above the amounts included in the approved 2016 BP for these scopes. Funding for construction of the Phase 1 landfill proper is not included in this sanction request, but will be requested at a later date in concert with the receipt of permits and initial bids of Landfill Phase I construction.

Phase I scope included in this request is comprised of the following components:

- EPC contract award to [redacted] for the CCRT system, including the bottom ash and gypsum dewatering systems, conversion of station fly ash transport from wet to dry conveyance, fly ash storage silos, pipe conveyor from the CCRT area to the landfill location;

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[1] Co-Owners of the Trimble County plant: Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA) are responsible for 25%. IMEA owns 12.12% and IMPA owns 12.88%.
[2] This amount is \$31.0m (Gross) greater than 2016 BP process. Total does not include Bottom Ash Pond/Gypsum Storage Pond (BAP/GSP) or Holcim project costs.
[3] This amount is \$21.0m (Gross) greater than 2016 BP. The contingency is calculated based on a total CCRT EPC contract price of \$244.0m (Appendix D), which includes option pricing for various equipment, installation and engineering.

- Landfill engineering, permitting and construction
    - Landfill permitting engineering, studies and activities
    - Payment of landfill stream and wetland mitigation fees
    - Payment of Indiana Bat mitigation fees
    - Property Acquisition (properties to date and future purchases)
    - 345kV transmission line relocation in the future landfill area
    - Construction of the bridge, road and pipe conveyor to the future landfill area (this is managed under the CCRT EPC as a separate release)
    - Fencing and utility relocation in the future landfill area

While the bridge, road and pipe conveyor from the station up to the landfill area is included in this sanction, the project schedule and termination costs related only to transporting of CCRs (Transport Subproject[4]) to the landfill is estimated based on receipt of permit approvals by October 1, 2016. The EPC contract has provisions for addressing any duration delay or termination. If permit approval is received after October 1, 2016, the cost impacts would be agreed upon per terms of the contract based on date certain of permit issuance. The delay would result in transporting CCRs to the landfill via truck rather than the pipe conveyor. All other work would not be affected.

The EPC authorization request seeks approval to enter into a fixed price, lump sum contract (the "Contract") with [redacted] for the Trimble County CCRT EPC Contract Proposal. [redacted] was the EPC firm for the successful E.W. Brown Unit 3 baghouse project, the Trimble County Unit 1 baghouse project and is currently constructing the E.W. Brown 10 MW Solar facility. The EPC scope includes the engineering, procurement, and installation of one (1) 100% under-boiler submerged flight conveyor for dewatering Unit 1 bottom ash, two (2) 100% gypsum dewatering belts, vacuum/pressure fly ash transport system for Unit 1 and Unit 2, two (2) concrete fly ash silos, modifications to the plant's existing CCR handling systems, an overland pipe conveyor, ancillary balance of plant systems/components, and a bridge and road to the planned landfill area. This scope also includes demolition necessary to construct the scope listed above. This Contract is expected to begin in early April 2016 and be utilized through completion of the CCRT project in 2018.

With regards to our partners at Trimble County (i.e. IMPA and IMEA), they have reviewed the contract and sanction recommendation. There have been reviews held with both partners in joint meetings. Both partners are in favor of the EPC award and moving the requested sanction forward. Both partners expect to have their internal and board approvals by April 2, 2016 and be in a position to sign the EPC the first week of April, 2016.

Background

The purpose of the TC CCR Project is to provide dry permanent storage (a special waste landfill) for all CCR generated from the Station with an estimated 37 years or more of storage capacity. Based on projections of remaining life of the existing CCR disposal facilities (Bottom Ash Pond

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[4] The Transport Subproject costs are $59.0m (Gross). Termination costs due to Contractor prior to October 1, 2016 of $1.3m are owed for engineering and locking-in pipe conveyor delivery.

and Gypsum Storage Pond) at the Station, the landfill and CCRT construction should begin in 2016 in order to avoid more costly transport and disposal of CCR materials at an off-site location.

The landfill will be located in Ravine B, which is located east of the Station on property owned by LG&E. The footprint of the proposed landfill will occupy an estimated 189 acres. The major ancillary components of the landfill include a leachate pond, sediment pond, storm water collection and diversion ditches, soil borrow areas, a bridge and road across State Road 1838 to the landfill area, and a CCRT system including an overland pipe conveyor.

The project was approved by the Kentucky Public Service Commission (KPSC) in 2009 and reaffirmed for Phase I in late 2015. Permitting activities have been on-going continuously since 2009 and the landfill permit is expected to be issued by the KYDWM in the fall of 2016. The progression of the relevant and subsequent planning and regulatory coordination actions to date is summarized in Appendix B.

Project Description

The Trimble County CCR project includes the engineering, permitting, procurement, construction and commissioning of new CCRT facilities, as well as a new CCR landfill and associated infrastructure for the storage and management of CCR generated at the Trimble County Station. The CCRT facilities will collect, condition, dewater, store, and transport CCR materials (fly ash, bottom ash, gypsum) to the new landfill for storage. An overland pipe conveyor will be used for primary transport of the CCR materials to the landfill. The new landfill will be located on LG&E property in Ravine B which is located northeast of the power block on the east side of State Road 1838. A road and bridge over State Road 1838 will be constructed to provide access to the landfill area from the power block area.

The CCRT facilities will include a new Unit 1 and Unit 2 fly ash system consisting of pneumatic conveying equipment, fly ash silos, and conditioning equipment used for transport, temporary storage, and conditioning of economizer ash, air heater ash, and fly ash collected in existing electrostatic precipitators (ESP) and pulse-jet fabric filters (PJFF). A new Unit 1 bottom ash system will be constructed for dewatering and temporary storage of Unit 1 bottom ash. This scope includes a new reclaim system for Unit 1 bottom ash, Unit 2 bottom ash and pyrites, and Unit 1 pyrites. A new Unit 1 and Unit 2 gypsum dewatering facility will be constructed for dewatering and temporary storage of each unit's dewatered gypsum. This scope includes horizontal vacuum filters for gypsum dewatering and a portal reclaimer to recover stored gypsum. A series of new belt conveyors and an overland pipe conveyor will be constructed to transport the conditioned/dewatered CCR materials to the landfill.

The landfill will be designed and constructed to store CCR over an approximately 37 year period. The landfill will be developed in four construction phases with each fully integrated as an extension of the adjacent landfill phase or cell. Each phase will have an estimated lifespan (placement of CCR) of between 6 to 12 years. The landfill will be constructed with an engineered composite liner system consisting of a prepared subgrade, a synthetic liner, leachate collection system layer (including piping), and a protective clay soil cover. This system of engineered layers will be constructed in order to contain the CCR and collect leachate that may accumulate, while protecting groundwater. Additional infrastructure for the landfill facility will include paved haul roads, access roads, a drainage system to separate CCR contact water from non-contact surface water, a sediment basin and erosion control features for storm water management, a lined leachate pond, and groundwater wells for monitoring groundwater quality.

Contract Description

The CCRT EPC contract is a fixed price, lump sum contract negotiated by PE and Legal. The duration of the contract is approximately three (3) years with a two (2) year warranty period that ends on the second anniversary of Commercial Operation of the CCRT system. The Contract has been divided into four (4) Subprojects: Bottom Ash, Fly Ash, Gypsum and Transport. Each Subproject has its own independent Guaranteed Commercial Operation Date. The contract will be paid out in accordance with a milestone payment schedule commensurate with completion of the work. Individual milestone payments will not exceed work performed and the maximum monthly cash flow will be limited by the aggregate of the monthly milestones.

Additional components of the contract are listed below:

- Contractor is required to comply with all Health & Safety Requirements.
- No "First of a Kind" technology is acceptable without LGE-KU's written consent.
- Termination - convenience and cause, with the aggregate payment amount outlined on a percentage basis for each month of the contract through commercial operation.
- Delay Schedule for Transport Subproject – due to uncertainty associated with the timing of landfill permit approvals (required for construction of the Transport Subproject), a payment schedule is included with payment amounts for each month the Work associated with the Transport Subproject is delayed.
- Any legal action will be in the Federal District in Louisville, Kentucky, with no jury.
- The overall limit of liability is 100% of the Contract price.
- Liquidated Damages (LDs) – LD's shall apply to unit derate and outage hours, auxiliary power consumption limits as defined in Exhibit G, and availability.
- Performance Guarantees – Described in detail in Exhibit G of the Contract. Specific Performance Guarantees include: bottom ash dewatering system, fly ash conveying system, gypsum dewatering system, pipe conveyor system, sound emissions, dust emissions, reliability, and auxiliary power consumption.
- Warranty – Twenty-four (24) months after Commercial Operation for each Subproject. Any extended warranties from equipment manufacturers under this Contract flow to LGE-KU after the two (2) year warranty provided by [redacted].
- Insurance – Company named as additional insured and Contractor waives rights of subrogation and general liability limits as set forth and agreeable to our consultant, Risk Management Services Company. [redacted] will hold the overall builder's risk policy with policy limit to the value of the Contract.
- Intellectual Property – Contractor grants an irrevocable, permanent, transferable, sub-licensable, non-exclusive, fully assignable, royalty-free, paid-up license to copy, perform, display, and otherwise use the information and intellectual property to allow owner to operate, maintain, repair, train personnel, modify, improve, and alter the work.

- Indemnity – Indemnification by [redacted] includes third party claims, personal injury, property damage, claims by government authorities (arising from violation of law), and claims by government authorities for taxes and liens.
- Risk of Loss – Care, custody and control will pass to LGE-KU upon achievement of Commercial Operation.
- Performance Securities – The contract includes a parent guarantee from AMEC Foster Wheeler PLC and three (3) Letters of Credit totaling $45.0m (20% of $225.0m Contract value).
- Key Dates:

Table 1

Schedule Milestone		**Date**
Mobilization		2Q 2016
Fly Ash Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018
Bottom Ash Subproject	**Guaranteed Commercial Operation**	February 24, 2018
	Guaranteed Final Completion	March 30, 2018
Gypsum Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018
Transport Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018

Economic Analysis and Risks

- **Bid Summary**

After specification and conceptual development in concert with the Trimble County engineering and management team, a RFQ was sent to the following five (5) bidders on July 2, 2015: [redacted] and [redacted]. A pre-bid meeting was held at the Trimble County Station on July 21 and 22, 2015.

Bids were received on October 8, 2015, from four (4) bidders as [redacted] declined to bid. PE provided un-priced copies of the bids to the Trimble County Station staff, [redacted] and [redacted] for their use to complete a technical evaluation of the submittals. PE conducted an initial bid evaluation encompassing price (See Table 2 "Initial Proposal"), commercial terms and adherence to the technical specifications in preparation for bid review meetings (bidder presentations). As part of the initial bid evaluation process, technical bid clarification questions were developed and issued to all bidders.

Each of the bidders was required to present their proposed project teams, technical offering, and to demonstrate their understanding of the required scope, project execution, schedule and technical requirements. The bidder presentations took place during the week of November 2 2015, with participants from PE, Trimble County Station staff, [redacted] and [redacted] Multiple rounds of bid clarifications were issued to all bidders after the bid review meetings and were based on a review of schedule, cost, man-hours, unit quantities, and terms and conditions. These clarifications were intended to normalize bidders' responses for comparison to the required scope of work.

After reviewing the multiple rounds of clarifications, each bidder was evaluated on the following components of their proposal: safety, pricing, risk assessment, project plan, construction, schedule, technical plans and expertise, experience, project management and contract clarifications and exceptions. The combined rankings by the Station staff, [redacted] and PE are as follows: [redacted] 73.92, [redacted] 64.27, [redacted] 60.65, and [redacted] 45.16, with 100 being the maximum score. Complete rankings for all four (4) bidders are located in Appendix C – TC CCRT EPC Bid Evaluation Matrix. Zachry was eliminated from further consideration based on the Bid Evaluation Matrix results and a large disparity in price.

After these clarifications, several LGE-KU internal technical bid review meetings were conducted with PE, Trimble County Station Staff and [redacted]. These technical meetings primarily focused on issues associated with the proposals such as building layouts, maintenance access, equipment redundancy, plant operations, and proposed equipment suppliers. The proposals were reviewed in detail to verify compliance with the scope of work, identify opportunities for operation and maintenance improvements, incorporate clarifications to the specifications for a more complete adherence to the Trimble County Station standards, and agreement to the specifications. These additional technical reviews did not change the EPC Bid Evaluation Matrix results but aided in the consistency of Best and Final Offer (BAFO) from the remaining Short List bidders. On January 28, 2016, PE issued a list of technical clarifications to all three (3) remaining bidders, and requested that each bidder provide a BAFO.

After receipt and review of the BAFO from the remaining bidders, it was determined that [redacted] was the best evaluated bidder and had the lowest price among the bidders (see Table 2, BAFO).

To support further consideration of [redacted] proposal, PE visited a gypsum dewatering facility at a plant in Georgia which had previously been designed and constructed by [redacted] was responsible for engineering and construction; purchasing of major equipment was provided by the owner. PE's overall evaluation of [redacted] work was favorable, as their work product was equivalent to our current contractors. Discussions with the owner indicated they had no major issues with [redacted], and wouldn't hesitate to award the project to [redacted] again. In addition, LGE-KU has a significant amount of experience working on large EPC contracts with [redacted] (e.g. – Trimble County Unit 1 PJFF, E.W. Brown PJFF and Solar Projects.)

The PE commercial team and Legal met with [redacted] on several occasions starting January 11, 2016, to review technical and commercial matters. Performance guarantees, warranties, LDs, performance securities and insurance requirements were discussed among other key project topics. During this process, there were no serious obstacles to overcome in an effort to reach agreed upon contractual terms with [redacted]. Certain schedule, equipment, and commercial offerings resulted in the agreed Initial Lump Sum Contract Award as shown in Table 2 below.

Table 2 (CONFIDENTIAL DUE TO BID DATA)

Competing Bids ($ in Millions Gross)				
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BAFO	[redacted]	[redacted]	[redacted]	[redacted]
Initial Lump Sum Contract Award	$[redacted]			

- **Financial Summary**

Table 3 below highlights the budgeted amounts as reflected in the approved 2016 Business Plan (BP) against [redacted] BAFO cash flows, inclusive of 5% contract management contingency.

Table 3

Contract Expenditures ($ in Millions Gross)	Prior to 2016	2016	2017	2018	Total [2]
2016 BP [1]	$0	$88	$87	$60	$235
Total Contract Authorization Seeking Approval[3]	$0	$87	$79	$90	$256
Variance to 2016 BP[2]	$0	($1)	($8)	$30	$21

1 – Costs shown are for the portions of Phase I which pertain to the scope of the CCRT Contract.

2 – The 2017 BP will be updated based on the cash flows developed during final negotiations with AMEC along with the appropriate project contingencies.

3 – Total contract authorization is greater than initial lump sum bid for additional expenditures, due to studies, options, and plant requested items (See Appendix D – Project Cost Summary).

Table 4 lists the budget breakout that supports the current project forecast as compared to the 2016 BP. Any project overage will be addressed during the 2017 Business Plan process.

Table 4

Financial Detail by Year - Capital ($000s) (all amounts are Gross)	Pre 2016	2016	2017	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	36,435	128,114	134,579	146,323	15,694	16,772	-	477,917
2. Cost of Removal Proposed	-	-	-	-	-	-	11,742	11,742
3. Total Capital and Removal Proposed (1+2)	36,435	128,114	134,579	146,323	15,694	16,772	11,742	489,659
4. Capital Investment 2016 BP	43,362	141,097	124,391	109,481	12,094	16,772	-	447,197
5. Cost of Removal 2016 BP	-	-	-	-	-	-	11,742	11,742
6. Total Capital and Removal 2016 BP (4+5)	43,362	141,097	124,391	109,481	12,094	16,772	11,742	458,938
7. Capital Investment variance to BP (4-1)	6,928	12,982	(10,188)	(36,842)	(3,600)	-	-	(30,721)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	6,928	12,982	(10,188)	(36,842)	(3,600)	-	-	(30,721)

Note: Amount requested of $489.0m (Gross) is $31.0m (Gross) greater than 2016 BP; however, the project overage will be adjusted during the 2017 BP process. The $31.0m (Gross) overage is comprised of $21.0m (Gross) greater costs than the 2016 BP amount for the EPC, and $10.0m (Gross) greater than the 2016 BP amount for costs other than the EPC. Totals do not include BAP/GSP or Holcim project costs.

- **Risk of Contract**
  The risks of the Contract are as follows:

  - **Price Risk:** The EPC Contract is to be a fixed price, lump sum contract.

  - **Schedule Risk:** The project has a very aggressive timeframe that [redacted] believes they can meet. The Transport Subproject schedule is estimated based on receipt of permit approvals by October 1, 2016. Any change in permit issuance from the state/federal agencies will result in Guaranteed Commercial Operation Date and Final Completion Date adjustments only to the Transport portion of the CCRT EPC. The Bottom Ash Subproject will be installed during the fall 2017 eight (8) week outage on Unit 1. The work associated with this outage is scheduled to be completed in six (6) weeks to allow time at the end of the outage timeframe for cold-commissioning. The major risk of not proceeding is the remaining life of the BAP due to water volume and the pH operational issues associated with the existing CCR transport water systems. Delaying the CCR treatment portion of the overall Trimble County CCR Project is not recommended. This significant risk of delay was clearly communicated in the KPSC review held in late 2015.

  - **Financial Risk:** A financial analysis of [redacted] was conducted by the Company Credit Department before prequalification and after BAFO. The review of the financial statements yielded an adequate rating. [redacted] is providing Letters of Credit (which would represent 20% of the Contract value), and [redacted] is providing a parent guarantee.

  - **Risk Mitigation Factors:** Components of the Contract that are designed to mitigate the risks of the Contract are described in the Contract Description section of this paper.

- **Other Alternatives Considered**

  - A "do nothing" alternative was not considered due to the requirements for the new CCRT system described previously.
  - A rigorous bid process was held where four (4) bidders were considered and the recommended contractor meets the technical and commercial requirements to complete the project. Award to an alternate acceptable bidder at a minimum $6,000k higher cost.
  - Due to potential permit delay related to the Transport Subproject, this work would be deferred until the landfill permit was obtained. This delay affects placement of the CCRs in the landfill. The balance of scope associated with Fly Ash handling, TC1

Bottom Ash conversion from wet-to-dry, and Gypsum dewatering would be completed by the EPC per the agreed schedule. Various options have been documented to management and governmental agencies that specifically list numerous options for CCR placement that include on-site, sending CCRs off-site related to beneficial use arrangements, or transport to another permitted location off the Trimble County site.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised Trimble County Coal Combustion Residuals Project – Phase I sanction for a total authorization of \$369.0m (Gross) which releases all scopes on the project except for the construction of the landfill proper.

It is recommended that the Investment Committee approve the award of the Trimble County Coal Combustion Residual Treatment & Transport EPC contract to [redacted] for an initial award amount of \$225.0m (Gross) and a total contract authorization of \$256.0m (Gross), which is inclusive of a 5% contract management contingency.

Joan S. Lipp	Anthony L. Ruckriegel 4/5/2016
Joan S. Lipp Mgr. Major Capital Projects	Anthony L. Ruckriegel Mgr. Contracts/Major Capital Projects
4/5/16	4/5/16 DOA for J. Voyles
R. Scott Straight Dir. Project Engineering	John N. Voyles VP Transmission & Generation Services
Ralph Bowl 4/6/16	4/6/16
D. Ralph Bowling VP Power Production	Paul W. Thompson Chief Operating Officer
KfWblake 4/7/16	4/11/16
Kent W. Blake Chief Financial Officer	Victor A. Staffieri Chief Executive Officer

APPENDIX A

Investment Proposal for Investment Meeting on October 15, 2009

Project Name: **Trimble County CCP Project**

Total Expenditures: **Phase I – $79,720k (net) & Total Project – $227,973k (net)**

Project Number: **127135 and 127134**

Business Unit/Line of Business: **Generation Services/Project Engineering**

Prepared/Presented By: **R. Waterman/J. Heun/S. Straight/T. Crutcher**

Executive Summary

The Coal Combustion Products (CCP) from the Trimble County Generating Station are treated and stored at on-site facility called the Bottom Ash Pond (BAP). The CCP materials include gypsum, bottom ash, fly ash, and pyrites. In addition, the pond is used to treat and store waste materials from various operating sumps. The BAP is located at the far north end of the Generating Station and was constructed with Unit 1. Recent bathymetric (volume) surveys indicate that the BAP will be at capacity in early 2011, several months after Unit 2 is scheduled begin commercial operations.

The Trimble County CCP Project has been under development for over four years. The Project has been divided into two stages. The first stage is the extension of the BAP Dikes and lining of the Gypsum Storage Pond (GSP). This first stage has been previously approved by the Investment Committee and work is currently in progress. This first stage will provide incremental storage until the second stage can be placed into service. The second stage of the CCP project includes the development, permitting and construction of a landfill at the head of Ravine B. Approval for the second stage of CCP project is sought in this Investment Paper.

MACTEC was contracted in 2005 to provide an Initial Siting Study (Conceptual Engineering) and subsequently retained to perform additional studies related to the project. Additional studies performed by MACTEC include Final Conceptual Study for Impoundments, Initial Siting Study for Landfills, and Final Conceptual Study for Landfills. Detailed descriptions of the studies performed are provided in the Project Description section of this paper.

Based on the numerous studies performed by [redacted], NPV cost analysis, environmental concerns, and permitting issues (KPDES and KDWM) it was determined that Case 21 was the best alternative for long term CCP storage. Case 21 is a single combined landfill in upper Ravine B with a pipe conveyor for CCP transport from the plant to the storage facility, a design life of 40 years, and a final crest elevation of 910 feet above sea level. Further NPVRR analysis supports this selection of Case 21 and the results of the analysis are proved in the Financial Summary section.

Total capital cost for the overall project is projected at $303,964k (gross) and is based on Level I Engineering. Capital cost for Phase I only is $106,293k (gross) and will provide 12-years of the 40-year design life. All phases of the Trimble County CCP Project are eligible for ECR recovery and a request to recover Phase I expenses was included in the June 2009 ECR filing. Phase II and Phase III activities will be presented to the Investment Committee for approval and seek ECR recovery at a later date.

Project Description

- **Project Scope and Timeline**

Initial Siting Study
During the Initial Siting Study performed by [redacted] approximately twelve (12) on-site and off-site storage options were considered in addition to the evaluation of various material handling alternatives. Ultimately, a decision was made to pursue the storage of CCP materials in Ravines A and B.

The ravines were purchased and permitted by LG&E during the construction of Unit 1 for the purpose of landfilling the CCP materials. However the landfills were never constructed. The ravines are located northeast of the power block and are contiguous with the remainder of the Trimble County Generating Station properties.

Final Conceptual Study for Impoundments
Based upon the Initial Siting Study results, [redacted] was retained to perform the Final Conceptual Design. As part of this study, a decision was made in December, 2006 to pursue the incremental storage of CCP materials in the existing Bottom Ash Pond and Gypsum Storage Pond (GSP) due to their lower cost per ton of storage. This also provided storage contingency during the development, permitting, and construction of CCP storage in the ravines.

Simultaneous to the engineering design of the BAP and GSP, [redacted] continued to evaluate storage options in the Ravines. Twelve (12) sets of design parameters were considered for three (3) scenarios which included fly ash in Ravine A, gypsum in Ravine B, and both materials in Ravine B along with various numbers of dike alternatives. Both landfills and impoundments were considered along with various CCP transport methods.

Ultimately, the E.ON U.S. project team selected a 40-year storage plan which consisted of an ash pond in Ravine A (Scenario 6) and a gypsum pond in Ravine B (Scenario 10). [redacted] then began developing a phased construction approach for the storage facilities.

The Final Conceptual Study was completed in late 2008. In December 2008, prior to start of the Detailed Engineering Design for impoundments, E.ON U.S. received word that the US EPA Region IV would reject the Trimble County KPDES permit modification application. This rejection was due to the use of fly ash water for use in the FGD processes at Trimble County and the plan to discharge gypsum sluicing water to the Ohio River. As a result of this decision the use of impoundments to treat CCP materials was reviewed and it was determined that due to a significant water balance issue for the station once TC2 became operational, impoundments were no longer feasible and the CCP materials would need to be placed in a landfill.

Initial Conceptual Study for Landfill Development
[redacted] in early January 2009 was commissioned to develop an Initial Conceptual Design for a landfill in Ravines A and/or B utilizing various material transport options included sluicing, trucking, pipe conveyor and dense slurry systems. This resulted in a total of nineteen (19) initial cases being evaluated during the Initial Conceptual Design.

During an April 8, 2009 review meeting, the majority of the storage scenarios were eliminated from further consideration due to cost, permitting, or other significant reasons. Ravine A options were eliminated since all CCP material could be stored in Ravine B and trucking of CCP material to the ravine area was eliminated due to fugitive dust issues. Other cases were added as "hybrids" by combining some of the above cases.

[redacted] and E.ON U.S. met with the Kentucky Division of Waste Management (KYDWM) on April 17, 2009 to review the remaining conceptual storage scenarios. During this meeting, the agency expressed a preference to locate storage facilities in one ravine and to avoid storage facilities in both ravines confirming our decision during the April 8, 2009 review meeting. The use of only one ravine would be better received by the surrounding public and potentially less opposition would occur during the permit review process. The KYDWM also acknowledged that E.ON U.S. has an existing permit for development of a landfill in both Ravines A and B and indicated that the "new" permit application would be considered a "major permit modification."As a result of this meeting, no further consideration was given to landfill storage in Ravine A.

After several additional cases were eliminated, revised cash flow projections were developed and an initial draft report was issued on April 30, 2009. Based on the updated cost estimates, NPVRR analysis, and environmental issues, the Initial Siting Study recommended 3 cases for further development (Case 16, 21, & 23).

Final Conceptual Study for Landfill Development

The three remaining cases were further evaluated during the Final Conceptual Design. At this stage, all storage options were normalized to a 40-year storage life based on tonnage projections provided by E.ON U.S. Generation Services. Case 16 is two separate landfills, one for gypsum and one for fly ash. Cases 21 and 23 are combined landfills with slightly different configurations. A major difference between the alternatives it the peak elevation of the landfill above sea level as noted below.

Case	Peak Elevation
16	980 feet
21	910 feet
23	1000 feet

Cases 16 and 23 both have the disadvantage of the high peak elevation. The surrounding ridges are at elevation 800 feet approximately. Cases 16 and 23 would both be nearly 200 feet above the existing peaks, nearly the same elevation as the top of the stack at Trimble County. Fugitive dust emissions are a critical issue to the Trimble County Title V permit. The emissions are a function of the height of the landfill, so Case 21 is the favored case. Further, the permitting difficulty is also a function of the landfill height. The greater height will result in greater public opposition due to view shed issues. Taking into account the elevations and permitting issues of the three (3) cases along with the NPV and subsequent NPVRR analysis, Case 21 is the landfill design selected and the design this request is based upon.

Permit Studies for Landfill Development

Many of the permit studies for the previous impoundments have been completed and are also applicable to the landfill and will not be required to be repeated. However, additional studies will be required for the Indiana Bat and possibly additional studies for the historical structures as a minimum.

- **Project Cost**

  The total project cost of Case 21 (Phases I, II & III) including engineering, permitting, and construction is $303,964k (gross), including Phase I at $106,293k (gross).

APPENDIX A

Authority is requested now for $106,293k (gross) to fund the following:

- On-going engineering for landfill development, including the engineering for the CCP transportation systems, access roadways, and utilities. (Previous authority has been granted for developmental engineering.)
- Permitting of the landfill.
- Construction of Phase I of the landfill consistent with Case 21

It should be noted that budget estimates are based on Level I Engineering, the 2008 [redacted] estimated and other sources. A line-by-line contingency was added to each line item. This amount varied between 10% and 40% with a weighted average of 25% along with a 5% contingency applied to the overall estimate, 3.5% for E.ON U.S. overheads, and 6% annual escalation consistent with the 2010 MTP. Requested contingency is in line with the level of engineering and based on results from Phase I of the Brown ATB Project currently under construction. The construction contracts will be competitively bid and will likely include firm priced unit rates for units of work that cannot be defined via detailed engineering, as well as a lump sum component for fully engineered and predictable activities.

Economic Analysis and Risks

- **Assumptions**
  The design life of the first phase of landfill development is assumed to be approximately 12-years (2013 to 2024). The total life is projected at 40-years for the storage of bottom ash, fly ash, gypsum, and pyrites.

- **Financial Summary**
  Per E.ON U.S., an inflation rate of 6% and a discount rate of 5.4% were used for the time-value-of-money calculations. E.ON U.S. overheads were added at 3.5%. Allowances were made for mitigation of the Indiana bat, which have been found in the project area in the summer of 2009. The total capital and operational costs for storage of ash and gypsum were calculated in 2009 dollars and inflated, then discounted using the present worth method. All phases were projected to be capped in the same years. The cash flow spreadsheet results for the final round of preliminary conceptual design are summarized in the table below:

Case	NPV ($1,000)	NPVRR ($1,000)	Storage Capacity (yd^3)	Cost per Cubic Yard (2009)
16	$345,414	$357,800	36,900,000	$ 9.70
21	$300,631	$268,500	36,900,000	$ 7.28
23	$309,940	$276,400	37,200,000	$ 7.43

The NPV and NPVRR analysis, shown above, indicates that Case 21 is the best case for long term CCP storage for Trimble County.

APPENDIX A

A comparison between the 2009 and 2010 MTP/LTP plan and requested capital expenditure for Phase I is given below.

GAAP	Pre 2009	2009	2010	2011	2012	2013	Total
Case 21 (Net)	$1,500	$500	$500	$37,486	$39,734	$000	$79,720
2009 MTP/LTP	$000	$1,500	$6,900	$27,100	$45,500	$20,400	$101,400
Variance w/2009	**($1,500)**	**$1,000**	**$6,400**	**($10,386)**	**$5,766**	**$20,400**	**$21,680**
2010 MTP/LTP	$1,500	$500	$500	$34,000	$36,100	$000	$72,600
Variance w/2010	**$000**	**$000**	**$000**	**($3,486)**	**($3,634)**	**$000**	**($7,120)**

The capital cost for this investment proposal is $106,293k gross ($13.14 per cubic yard for on-site storage), or $79,720k net.

Financial Summary ($000s):	
Discount Rate CEM Model:	6.30%
Discount Rate NPVRR Model:	7.76%
Escalation	6.0%
Estimated Capital Breakdown:	
Labor & Equipment*:	$47,457
Materials*:	$15,819
Contingency (25%):	$16,444
Net Capital Expenditure:	$79,720k
NPV:	($2,887)
IRR**:	5.6%

* Assumes a 75/25 split between Labor/Equipment and Materials.
** The IRR is lower by approximately 2% points due to the less than 100% retail recovery percentage (taking into account OSS, FERC, and municipal portions).

Financial Detail by Year ($000s)	**Pre 2009**	**2009**	**2010**	**2011**	**2012**	**Phase I Total**
Project Costs (Capital proposed)(Net)	$1,500	$500	$500	$37,486	$39,734	$79,720
Project Costs (Cap. interest, if applicable)	-	-	-	-	-	-
Total project costs proposed (Net)	$1,500	$500	$500	$37,486	$39,734	$79,720
Project Costs (Capital, 2010 MTP)(Net)	$1,500	$500	$500	$34,000	$36,100	$72,600
Project Costs (Cap. interest 2010 MTP)	-	-	-	-	-	-
Total project costs 2010 MTP (Net)	$1,500	$500	$500	$34,000	$36,100	$72,600
Variance to 2010 MTP	$000	$000	$000	($3,486)	($3,634)	($7,120)
Project Costs (Cost of removal)	-	-	-	-	-	-
Project Costs (Cost of removal 2010 MTP)	-	-	-	-	-	-
Variance to 2010 MTP	-	-	-	-	-	-
Project Costs (O&M, proposed)(Net)	-	$000	$000	$000	$000	$000
Project Costs (O&M, 2010 MTP)	-	-	-	-	-	-
Variance to 2010 MTP	-	$000	$000	$000	$000	$000
EBIT	$59	$164	$213	$1,987	$5,348	$111,897
ROCE	4.0%	9.4%	9.5%	9.4%	9.0%	11.2%

APPENDIX A

- **Sensitivities**

Sensitivities	Change in EBIT					Change in NPV Total
	Pre-2009	2009	2010	2011	2012	
Project Costs (Capital +/-10%)	$6	$16	$21	$199	$535	($265)
Project Costs (O&M +/-10%)	$0	$0	$0	$0	$0	($24)

- **Environmental**
  Permits for Trimble County CCP Storage Project, include, but not limited to:
  - KDWM Landfill Permit – 1 to 2 years
  - Corp of Engineers Individual 404 Permit –1 to 1 ½ years
  - KYDOW 401 Permit – 1 to 1 ½ years
  - KYDOW Dam Safety Permit (if required) – 90 days

New Source Review Evaluation, questions 1-6 (as applicable) must be completed on all investment proposals.		
1	Does the project include any new equipment or component with emissions, result in emissions not previously emitted or cause the unit to exceed any emission limit? If yes, Environmental Affairs is required to review this project. If no, go to Question #2.	**YES[1]**
2	Question 2: Is the change a like-kind or functionally equivalent replacement under $500K? If yes, the project is not subject to NSR and no further evaluation is required. If no, go to Question #3.	**NO**
3	Question 3: Does the equipment change increase the emissions unit's maximum hourly heat input? If yes, Environmental Affairs is required to review this project. If no, go to Question #4.	**NO**
4	Question 4: Does the equipment change increase the emissions unit's electrical output? If yes, Environmental Affairs is required to review this project. If no, go to Question #5.	**NO**
5	Question 5: Has the equipment being repaired/replaced been repaired or replaced in the past at this unit or other units in the fleet? If no, Environmental Affairs is required to review this project. If yes, list any known projects and go to Question #6.	**NO**
6	Question 6: Have there been forced outages or unit de-rates in the past 5 years due to this component? If no, the project is not subject to NSR and no further evaluation is required; if the answer is yes, Environmental Affairs needs to review this project.	**NO**

[1] The CCP transportation system will be an emission source. The Environmental Affairs Department was included in the development of the Trimble County CCP Landfill and agrees with the chosen path forward.

APPENDIX A

- **Risks**

  Schedule – If the Trimble County Landfill is cancelled or delayed, the existing BAP and GSP will reach capacity by 2014. To keep the station operating beyond this date, CCP materials would have to be transported to an offsite storage facility at an estimated 2009 cost of $25-$30 per ton. This is several times more expensive than the capital and O&M costs of the landfill in the ravine.

  Beneficial Reuse – Remaining life of the BAP, GSP, and the Landfill can be extended if beneficial reuse opportunities materialize.

  Weather – Weather will play a major role as earthwork construction is difficult during wet and freezing conditions. If the project experiences extreme wet or cold conditions this could delay the completion of the project. The schedule developed accounts for average weather risk.

  Oil Prices – The cost of oil is another risk as oil has a direct affect on material placement unit rates as well as petroleum based products such as flexible membrane liners and filter fabrics. The 6% annual escalation is a composite rate that includes the projected cost of oil per Generation Planning.

  Permits – Denial or litigation of any of the permits could result in a substantial delay. Of particular concern would be the KYDOW 401 and Corp of Engineers 404 permits as well as the KDWM Special Waste landfill permit.

  Endangered Species - During a previous environment study, a juvenile female Indiana Bat was discovered. The Indiana Bat is classified as a Threatened and Endangered Species and as such, is protected by Commonwealth of Kentucky and Federal Law. Certain fees will be applicable for the destruction of the trees in the area of the new landfill. These fees will be negotiated between E.ON U.S., US Fish & Wildlife and Kentucky Fish & Wildlife. The applicable fee could be as high as $9,000/acre. With a landfill footprint up to 270 acres, the fees could approach $2.5 million. This amount is covered in the sanction request.

- **Other Alternatives Considered**

  Numerous combinations of landfills/ponds, materials stored, transportation methods, and locations were considered. In addition, several off-site alternatives were investigated. A "Do Nothing" alternative was not considered as this approach would require CCP disposal at a third party facility which is a very costly short term solution and doesn't meet the plants long term disposal needs.

Conclusions and Recommendation

Due to the rapidly decreasing storage capacity of the existing BAP, along with Case 21 having the lowest NPVRR cost, the least view shed issues, and the lowest peak elevation, it is recommended that the Investment Committee approve the overall Trimble County Landfill Project for $227,973k (net) and sanction Phase I for $79,720k (net) to meet the long-term CCP storage needs of the station.

APPENDIX B – TC CCR Project Key Dates

- 1979: LG&E performed a hydrogeologic investigation of Ravines A and B to assess the land's suitability for storage of CCR materials.
- 1984: LG&E proceeded with the design of disposal facilities and obtained a permit to construct a special waste landfill for CCR storage in Ravine A and B from the KY Department of Environmental Protection.
- 2005: LG&E performed a fleet-wide study of CCR storage facilities at all coal-fired generating stations. The study identified that the existing Trimble County Generating Station BAP did not sufficient disposal capacity for the long-term operation of the station. An *Initial Conceptual Design Study* considered various off-site and on-site storage alternatives and the Two-Part (short-term and long-term) Storage Plan was developed.
- 2006: The long-term part of the storage plan was developed in more detail in the *Final Conceptual Design Phase* report by [redacted] LG&E initiated correspondence with the KY Division of Water (KDOW) and the US Army Corps of Engineers (USACE) concerning the long-term disposal of CCR material and an initial meeting was held in early 2007 which was followed by several exchanges of information and requests.
- 2008: The conceptual design identified a wet disposal option (e.g., impoundment) in Ravine A and B as the recommended alternative.
- 2009-2010: With the addition of Unit 2 CCR production (in 2010), LG&E commissioned a *Final Conceptual Design Report* (2009), prepared by [redacted] which resulted in a landfill site in the upper reach of Ravine B (originally identified as Case 21) being the recommended site alternative. The US Environmental Protection Agency's (USEPA) 2010 release of a proposal to regulate CCR handling further reinforced this decision to initiate the design of a dry storage facility, or landfill.
- 2009: LG&E received ECR/CCN approval from KPSC to construct Phase I (based on landfill Case 21).
- 2010: LG&E submitted a 401/404 application to KDOW and USACE.
- 2011: LG&E submitted a special waste landfill permit application for the revised landfill design referred to as Plan II-3D to the KY Division of Waste Management (KDWM.
- 2012: In response to USEPA's request, LG&E and GAI performed a comprehensive review of the original site alternatives that were documented in the Alternatives Analysis report, in addition to evaluating and comparing additional site alternatives. The purpose was to more definitively demonstrate that the selected alternative is the least environmentally damaging practicable alternative.
- 2013: The KDWM denied the special waste landfill permit application for the selected alternative plan (Plan II-3D) based on its impact to a small karst feature known as the "Lime Cave" or "Wentworth Cave."

- 2013: LG&E and GAI reviewed several landfill alternative designs to avoid the "Lime Cave" and other small karst features; the Alternative Plan IIC-4B was selected as the least environmentally damaging practicable alternative using the Alternatives Analysis process.

- 2014: LG&E submitted a new special waste landfill application for the revised landfill design referred to as Plan IIC-4B to KDWM in January.
- 2014: LG&E submitted a permit application to construct a bridge over State Road 1838 to KY Transportation Cabinet (KTC) Department of Highways in January.
- 2014: LG&E submitted a new 401/404 application for the revised landfill design referred to as Plan IIC-4B to KDOW and USACE in April.
- 2014-2015: In January, 2014, GAI prepared an Alternatives Analysis Report which determined that the Ravine B project is the Least Environmentally Damaging Practicable Alternative (LEDPA) for LG&E's CCR facility. Region 4 of the U.S. Environmental Protection Agency wrote letters to USACE dated July 11, 2014 and August 7, 2014. These letters asserted that the Ravine B project is not environmentally acceptable, and that LG&E's alternatives analysis had not adequately justified its conclusion regarding the LEDPA. EPA recommended denial of the 404 permit application for the project as it was currently proposed. LG&E worked with Baker Botts LLP, Lee Wilson & Associates, LLC, and GAI to develop a Supplement to the Alternatives Analysis report which was intended to be a response to the two EPA letters referenced above. The Supplement was submitted to USACE in December, 2014.
- 2015: A privately held company, Sterling Ventures, filed a complaint with the KPSC, claiming that LG&E-KU should use Sterling Ventures' underground limestone mine for off-site storage of CCR, and that the KPSC should revoke all or portions of its previous orders. After several rounds of data requests from both parties, the KPSC granted LG&E-KU's request to affirm the Companies' existing CPCN and ECR authority for the Trimble County Landfill and related facilities, including the CCRT, for Phase I of the landfill and denied Sterling Ventures' request to revoke LG&E/KU's CPCN to construct the Trimble County Landfill.
- 2015: LG&E received approval of the KTC permit for bridge construction in November.

CONFIDENTIAL INFORMATION REDACTED

TC CCRT
BID EVALUATION MATRIX

Evaluation No.	Evaluation Category	Evaluation Factor	Category Value Points	Max Points Per Item
	Commercial		35	
1	Safety (Reviewed by Chuck Hance - see Prequalification Folder)			
		Meets Standards - Yes/No		
		LTIRC		
		RIR		
		EMR		
2	Pricing (see All Bidders Summary - BAFO 2-3-16 worksheet)			
		Base Scope		17.0
		Options		6.0
		Exhibit R Rates - Labor and Equipment (see individual Exh R in bi		2.0
3	Risk Assessment (see Bid Risk Assessment 1-19-16 worksheet)			10.0
		Total Commercial Score -		
	Technical		65	
4	Project Plan			
		Engineering Plan/Narrative (Design/Technical)		6.0
		Construction Plan/Narrative		6.0
		Safety Plan/Narrative		3.0
5	Construction			
		Bottom Ash Subproject (Option 1)		5.0
		Gypsum Subproject		5.0
		Fly Ash Subproject		5.0
		Transport Subproject (Option 2)		5.0
		Reclaim Water Tanks - Option 3		2.0
		Construction Manhours		4.0
		In-house Work vs Subcontracted Work		2.0
6	EPC Technical Bid Compliance			6.0
7	Planned Schedule			6.0
8	Technical Expertise			3.0
9	CCRT Experience			3.0
10	Major Subcontractors/Suppliers (Exhibit E Compliance)			2.0
11	Alternate Technical Offerings			2.0
		Total Technical Score -		
		TOTALS:	100	100

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	5	N/A	N/A	5.00	17.00
Options	N/A	N/A	1	N/A	N/A	1.00	1.20
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	4	N/A	N/A	4.00	8.00
Total Commercial Score							27.40
Engineering Plan/Narrative	4	4.25	N/A	4	N/A	4.08	4.90
Construction Plan/Narrative	4	4.25	N/A	5	N/A	4.42	5.30
Safety Plan/Narrative	4	4	N/A	N/A	N/A	4.00	2.40
Bottom Ash Subproject	4	4	N/A	4	N/A	4.00	4.00
Gypsum Subproject	4	4	N/A	4	N/A	4.00	4.00
Fly Ash Subproject	4	4	N/A	4	N/A	4.00	4.00
Transport Subproject	4	4	N/A	4	3	3.75	3.75
Reclaim Water Tanks	4	4	N/A	4	N/A	4.00	1.60
Construction Manhours	4	3.5	N/A	3	N/A	3.50	2.80
In-house Work vs Subcontracted Work	4	4	N/A	3	N/A	3.67	1.47
EPC Technical Bid Compliance	4	4.75	N/A	4	N/A	4.25	5.10
Planned Schedule	4	4	N/A	4	N/A	4.00	4.80
Technical Expertise	4	4	N/A	4	N/A	4.00	2.40
CCRT Experience	4	4.5	N/A	4	N/A	4.17	2.50
Major Subcontractors/Suppliers	4	4.75	N/A	4	4	4.19	1.68
Alternate Technical Offerings	4	3	N/A	3	N/A	3.33	1.33
Total Technical Score							46.52
						TOTAL POINTS	73.92

Scoring System
0 (unacceptable) through 5 (exceptional)

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	4	N/A	N/A	4.00	13.60
Options	N/A	N/A	5	N/A	N/A	5.00	6.00
Exhibit R Rates	N/A	N/A	2	N/A	N/A	2.00	0.80
Risk Assessment	N/A	N/A	1	N/A	N/A	1.00	2.00
Total Commercial Score							22.40
Engineering Plan/Narrative	3	3.75	N/A	4	N/A	3.58	4.30
Construction Plan/Narrative	3	3.75	N/A	4	N/A	3.58	4.30
Safety Plan/Narrative	4	4	N/A	N/A	N/A	4.00	2.40
Bottom Ash Subproject	3	3.5	N/A	4	N/A	3.50	3.50
Gypsum Subproject	4	3.5	N/A	4	N/A	3.83	3.83
Fly Ash Subproject	4	3.5	N/A	4	N/A	3.83	3.83
Transport Subproject	4	3	N/A	4	3	3.50	3.50
Reclaim Water Tanks	4	3.5	N/A	4	N/A	3.83	1.53
Construction Manhours	3	3.5	N/A	4	N/A	3.50	2.80
In-house Work vs Subcontracted Work	4	3	N/A	4	N/A	3.67	1.47
EPC Technical Bid Compliance	3	3	N/A	4	N/A	3.33	4.00
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	3	4	N/A	5	N/A	4.00	2.40
CCRT Experience	3	4.25	N/A	5	N/A	4.08	2.45
Major Subcontractors/Suppliers	2	3	N/A	3	3	2.75	1.10
Alternate Technical Offerings	3	3.5	N/A	3	N/A	3.17	1.27
Total Technical Score							41.87
						TOTAL POINTS	64.27

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	4.5	N/A	N/A	4.50	15.30
Options	N/A	N/A	4.5	N/A	N/A	4.50	5.40
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	2	N/A	N/A	2.00	4.00
Total Commercial Score							25.90
Engineering Plan/Narrative	2	2.75	N/A	3	N/A	2.58	3.10
Construction Plan/Narrative	2	2.75	N/A	3	N/A	2.58	3.10
Safety Plan/Narrative	3	4	N/A	N/A	N/A	3.50	2.10
Bottom Ash Subproject	2	3	N/A	4	N/A	3.00	3.00
Gypsum Subproject	3	3	N/A	4	N/A	3.33	3.33
Fly Ash Subproject	3	3	N/A	2	N/A	2.67	2.67
Transport Subproject	3	3	N/A	4	3	3.25	3.25
Reclaim Water Tanks	3	3.5	N/A	4	N/A	3.50	1.40
Construction Manhours	3	3	N/A	4	N/A	3.33	2.67
In-house Work vs Subcontracted Work	3	3	N/A	4	N/A	3.33	1.33
EPC Technical Bid Compliance	2	3.5	N/A	2	N/A	2.50	3.00
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	3	3	N/A	3	N/A	3.00	1.80
CCRT Experience	3	2.5	N/A	3	N/A	2.83	1.70
Major Subcontractors/Suppliers	2	2	N/A	3	2	2.25	0.90
Alternate Technical Offerings	2	3	N/A	3	N/A	2.67	1.07
Total Technical Score							34.75
						TOTAL POINTS	60.65

[redacted] INC.

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	1	N/A	N/A	1.00	3.40
Options	N/A	N/A	1	N/A	N/A	1.00	1.20
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	3	N/A	N/A	3.00	6.00
Total Commercial Score							11.80
Engineering Plan/Narrative	2	3	N/A	3	N/A	2.67	3.20
Construction Plan/Narrative	2	2.5	N/A	3	N/A	2.50	3.00
Safety Plan/Narrative	3	4	N/A	N/A	N/A	3.50	2.10
Bottom Ash Subproject	2	3	N/A	4	N/A	3.00	3.00
Gypsum Subproject	2	3	N/A	4	N/A	3.00	3.00
Fly Ash Subproject	2	3	N/A	2	N/A	2.33	2.33
Transport Subproject	2	2.5	N/A	4	4	3.13	3.13
Reclaim Water Tanks	2	3.5	N/A	4	N/A	3.17	1.27
Construction Manhours	2	3	N/A	3	N/A	2.67	2.13
In-house Work vs Subcontracted Work	2	3.5	N/A	2	N/A	2.50	1.00
EPC Technical Bid Compliance	2	3.5	N/A	3	N/A	2.83	3.40
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	2	4	N/A	3	N/A	3.00	1.80
CCRT Experience	2	4	N/A	3	N/A	3.00	1.80
Major Subcontractors/Suppliers	2	2.5	N/A	3	4	2.88	1.15
Alternate Technical Offerings	1	3	N/A	3	N/A	2.33	0.93
Total Technical Score							33.36
						TOTAL POINTS	45.16

Notes:
1. TC Plant staff: a) reviewed the SOW/technical specification/schedule; b) were provided hardcopy and electronic copies of all bids (unpriced); c) participated in the Technical Presentation Meetings, and d) provided input for certain C&Es.

APPENDIX D - Project Cost Summary

[redacted]

CCRT EPC	$	Amount		2016 BP	Variance to 2016 BP[2]	
EPC Initial Award	$	[redacted]				
Tank Sizing / Equipment	$	2,000,000				
Geotechnical / Engineering Investigation Adjustments	$	4,000,000				
Service Water / Other Equipment	$	500,000				
Bottom Ash Demo / Service Building	$	1,000,000				
WFGD Bleed VFD and Piping	$	2,000,000				
CCR Material Characteristics	$	500,000				
Outage Change	$	200,000				
Transport Subproject Permit Delay (6 months)	[redacted]	[redacted]				
Stormwater/Sanitary Sewer Survey / Piping Upgrades	$	1,000,000				
Fire Protection Study / Upgrades	$	500,000				
Fly Ash Study Results / Engineering Changes	$	4,000,000				
Air Compressor Study Upgrades	$	500,000				
Auxiliary Power, Cathodic Protection, Grounding Studies Results / Changes	$	1,000,000				
CCRT EPC Subtotal	$	[redacted]				
5% contingency	$	[redacted]				
CCRT EPC Total	[redacted]	[redacted]	Gross	$ 235,000,000	$ 21,000,000	Gross
	[redacted]	[redacted]	Net			

Other and Non TC CCRT EPC	$	Amount		2016 BP	Variance to 2016 BP[2]	
[redacted]	[redacted]	[redacted]				
Spare Parts	$	2,500,000				
Gate, Security, Parking	$	2,000,000				
14kv Power Cable and Install (existing manholes)	$	2,500,000				
Property Acquisition	$	4,400,000				
345kV Line Relocation	$	6,200,000				
Owner Cost - Rolling Stock	$	2,200,000				
Expenses Prior to January 2016 (per 2016BP)	$	36,400,000				
Owner General Costs EPC Total x 3.5%	$	9,000,000				
Stream/Wetland/IN Bat Mitigation Fees	$	33,500,000				
Other and Non CCRT Subtotal	$	[redacted]				
5% contingency	$	[redacted]				
[redacted]	[redacted]	[redacted]		$ 103,000,000	$ 9,700,000	Gross
Project Total = EPC + Other and Non CCRT EPC (A)	[redacted]	[redacted]0	Gross	$ 338,000,000	$ 30,700,000	Gross
	[redacted]	[redacted]	Net			

Phase I Items Excluded from Project Sanction Request	$	Amount	
Phase I - Landfill Proper Construction[1] (B)	$	121,000,000	
Subtotal - Excluded Items	$	121,000,000	Gross
	$	90,750,000	Net

	$	Amount		Variance to 2016 BP[2]	
Phase I Total (A+B)	$	489,700,000	Gross		
Phase I Total Estimate (per 2016 BP)[2]	$	459,000,000	Gross		
Variance to 2016 BP[3]	$	30,700,000	Gross	$ 30,700,000	Gross
	$	23,025,000	Net		

Notes:
1. Includes costs for Phase 1 cover system. Haul Road and Bridge included in CCRT EPC.
2. The 2016 Business Plan for all Phases of the CCR Project is $709M.
   Phases 2, 3 and 4 costs that extend thru 2044.
   Total does not include BAP/GSP or Holcim.
3. The 2017 BP will be updated to include any variances.

Investment Proposal for Investment Committee Meeting on: 12/18/2020

Project Name: Mill Creek Primary Gypsum Slurry Tank Rehabilitation

Total Capital Expenditures: $2,645k (Including $345k of contingency)

Total O&M: N/A

Project Number(s): 162240

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Timothy Coomer

Brief Description of Project

This Authorization for Investment Proposal (AIP) seeks approval for the design and construction of the Mill Creek Station (the "Station") Primary Gypsum Slurry Tank Rehabilitation project and associated supporting scopes (the "Project").

In 2018, in order to optimize the gypsum dewatering system and reduce the risks associated with system or single component failures, the new Gypsum Dewatering Processing Plant (GPP) was installed with a complete one hundred percent (100%) redundant secondary tank system to the primary tank system this paper seeks authorization to rehabilitate.

As part of this GPP system upgrade, it was identified that the existing primary gypsum slurry tank has experienced aging issues. The existing tank coating, which was placed in service in November 2000, is currently experiencing coating failures. The failed coating has led to metal tank deterioration, structural steel integrity loss, and an expected shorter service life of tank components and infrastructure directly exposed to the slurry operational process.

As a result of the above issues to the primary gypsum slurry tank, this AIP seeks approval for the rehabilitation of the tank including the fabrication, procurement, and construction for all civil, mechanical, and electrical components, comprising the Project. The Project will be subdivided into the following 2 subprojects (the subprojects will comprise two [2] separate contracts):

- Subproject #1:
  - Relocation of underflow lines and mechanically/electrically air gapping existing secondary tank.
- Subproject #2:
  - Rehabilitation of the existing primary tank and all required process and service infrastructure.

The Project, shown as subprojects above, includes the major activities required to restore the tank to nearly original condition as follows:

- Removal and replacement of primary tank platform
- Installation of a new underflow valve platform (not located above the tank)
- Installation of new agitator (matching the Secondary Gypsum Tank)
- Remove and replace tank interior coating
- Rehabilitation of tank shell and exterior recoating
- Replacement of functionally obsolete and degrading primary tank stairwell.
- Replacement of Primary Tank Enclosure (constructed as temporary) into a permanent enclosure
- Demolition of existing agitators
- Electrical work to support new infrastructure and equipment

The Project timeline with these major milestones:

Item:	Completion Date:
Subproject #1 - Underflow Relocations and air gapping	March 31, 2021
Subproject #2 – Rehabilitation of the primary tank, coating and infrastructure installation	July 30, 2021

This rehabilitation project will increase the overall life of the primary tank to remain in line with the remaining life of the Mill Creek Station. This Project is part of the 2021 Business Plan. As part of the GPP project, this rehabilitation project is not included in an ECR filing.

Why is the project needed? What if we do nothing?

The degradation of the existing primary slurry tank could cause system failure within the next few years based upon the current condition of equipment and tank coating, as well as chemical attacks that will and have occurred due to failing coating systems. An independent third party inspection, conducted in August 2020, found that the tank has experienced structural steel integrity loss, substantive interior coating failures, and the exterior coating is quickly approaching the end of its usable lifecycle.

The inspection report recommends rehabilitation of the tank coatings and steel, in lieu of replacement of the tank as the tank steel and foundation are suitable to be rehabilitated to meet the service life needs of the Mill Creek Station; however, the tank will not remain viable for the life of the Station without substantial rehabilitation and updating in the very near future. The inspection identified considerable number of deficiencies of which some are notated in the Risks section below.

The Project is necessary for continued long-term operation of the recently commissioned GPP which allows for beneficial use of the gypsum byproducts. The gypsum byproduct sales for beneficial use has increased dramatically from 2015 to 2019. The tonnage beneficially used increased from 26% (171 ktons) to 87% (515 ktons) . With improved byproduct contracts in place, leading to increased revenues that are passed on to the customers, the necessity to perform the scope of work is even more justified. The beneficial use of the gypsum byproducts also extends the life of the onsite landfill and can limit the future expansion (the Phase 2 or 3 expansions) and those associated costs.

The Project will also improve agitator operation and reliability, as the current agitators are an outdated design, which results in sixty percent (60%) of the maintenance work orders. A new agitator, common to the secondary and rehabilitated primary tank, will be installed as part of the Project. The Station will reap lower overhead and maintenance costs plus increased system reliability.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	$ 2,345				$ 2,345
2. Cost of Removal Proposed	$ 300				$ 300
3. Total Capital and Removal Proposed (1+2)	$ 2,645	$ -	$ -	$ -	$ 2,645
4. Capital Investment 2021 BP	$ 2,975				$ 2,975
5. Cost of Removal 2021 BP					$ -
6. Total Capital and Removal 2021 BP (4+5)	$ 2,975	$ -	$ -	$ -	$ 2,975
7. Capital Investment variance to BP (4-1)	$ 630	$ -	$ -	$ -	$ 630
8. Cost of Removal variance to BP (5-2)	$ (300)	$ -	$ -	$ -	$ (300)
9. Total Capital and Removal variance to BP (6-3)	$ 330	$ -	$ -	$ -	$ 330

Financial Detail by Year - O&M ($000s)	2021	2022	2023	Post 2023	Total
1. Project O&M Proposed					$ -
2. Project O&M 2021 BP					$ -
3. Total Project O&M variance to BP (2-1)	$ -	$ -	$ -	$ -	$ -

Risks

Project and relevant risks include the following:

- If this Project is not undertaken, then the tank and supporting mechanical/electrical equipment will become less reliable and experience increased downtime in order to patch coating, install steel patch plates, perform piecemeal replacements/repairs of steel, platforms and exterior coating, replace tank valves (located above top of primary tank), and perform maintenance on outdated agitators and electrical power/control equipment.
- By taking the new primary tank out service, only the secondary tank is available for service. The major failure point for this tank is the agitator gearbox/motor. A capital spare has been purchased and its onsite storage is a prerequisite for rehabilitation of the primary tank.
- By not completing the Project, the reliability of the existing primary tank and its infrastructure continues to deteriorate to an unacceptable level, eventually creating an emergency condition for resolution of tank failure. Tank replacement or repairs at a future date, conducted on a compressed schedule, will increase the costs and create the risk of process/engineering errors due to the compressed schedule to conduct corrective actions.

- Potential risks to beneficial use customers would be averted by the rehabilitation for the life of the Station and ensuring the market would remain viable and profitable. Since the existing primary tank has not yet failed, the immediate risks are currently mitigated but are imminent without corrective actions. The agitator reliability presents ongoing challenges and higher maintenance costs.
- The Project is not subject to the New Source Review criteria per the Environmental Affairs Department.
- The nature of the Project has several schedule and scope risks which are included in the Project pricing as follows:
    a. The tank exterior repair scope is 'high risk' as not all metal repairs are currently exposed and the depth of the metal degradation is indeterminate.
    b. The tank exterior coating overlay (adding a new coat of exterior paint) has uneven amounts of remaining coating. This leads to a higher risk of coating removal in isolated areas which can affect cost and schedule.
    c. Major steel work, replacing primary tank platform and functionally obsolete stairwell, are subject to market risk due to the limited availability of steel galvanizers which has gotten worse with the Corona virus.
    d. The compact work area and operational secondary gypsum tank introduces more risk of delays with elevated work, containment concerns and adjacent road traffic. The area has considerable flux which can cause delays.
    e. In these current times, the risks associated with the Corona virus are challenging to identify and control. This alone can, and has on other recent projects, delay schedules and impact costs.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) $3,076

   Rehabilitation which includes relocating all three unit underflow lines, constructing new access platforms, electrical and heat tracing, improved infrastructure, removal of the existing primary tank interior coating, inspection/repair of existing primary tank, new primary system pump enclosure and exterior recoating with upgraded coating systems and would also include installing a state-of-the-art agitator.

   The Rehabilitation of Primary Slurry Tank with the addition of a new agitator, agitator structural steel, additional infrastructure, and substantive amount of demolition work. This recommendation provides the following benefits:

   - Spare parts reduction due to common agitator with the primary tank.
   - Supports life of the Station operational needs with lower capital cost than the tank replacement alternative
   - Supports the beneficial use sales of gypsum byproducts through the Station's expected operating life.
   - Avoids crisis management situation by implementing a disciplined and sufficiently robust scope to maintain the 2x100% operational configuration of the original system design by rehabilitation of tank. This scope also produces less downtime than a tank replacement project.

2. Alternative #1: NPVRR: ($000s) $0
   'Do nothing' would include any routine and preventive maintenance plus the costs of indeterminate repairs for the life of the existing primary tank. Although the existing primary tank could be patched, the nature of coating requires a smooth surface to properly adhere to the tank steel wall. Patching the coating is a short-term fix and doesn't positively affect the steel wall already under corrosive attack. A 'patch strategy' is not considered a viable operational strategy.

3. Alternative #2: NPVRR: ($000s) $3,460
   Total demolition and replacement of the primary tank including new agitator, new gearbox/motor and new infrastructure. This also includes relocation of all three unit underflow lines, constructing new access platforms, electrical, and heat tracing, and improved infrastructure.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mill Creek Primary Slurry Tank Rehabilitation project for $2,645k, inclusive of a 15% contingency, to ensure the continuation of long term operation of the Gypsum Processing Plant at the Mill Creek Generating Station.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project 156694 Hillside-Green River Plant Pole Replacement

Investment Proposal for Investment Committee Meeting on: January 30, 2019

Project Name: Hillside-Green River Pole Replacement

Total Expenditures: $2,635k
Total Contingency: $239k (10%)

Project Number(s): 156694

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Ronnie Bradford/Adam Smith

Executive Summary

The proposed project is to replace fifty-three (53) wood structures on the Hillside-Green River Plant 69kV line with new steel structures that were identified through inspection in 2017. Due to the difficulty in obtaining an extended outage, approximately 50% of the structures will be energized when they are replaced. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $140k.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

This project was included in the 2019 Business Plan (BP) for $1,482k. Subsequent to the 2019 BP planning, an additional eleven (11) structures were identified to be in need of replacement. In addition, a decision was made to complete 50% of the structures energized. Funding in the amount of $466k was included for structure access and matting. The incremental funding of $1,153k was approved by the RAC in the 0+12 forecast. See table below for a detailed breakdown of the cost changes.

Incremental Cost Detail	
11 Additional Structures	$547k
Energized Adder	$140k
Matting	$184k
Structure Access	$282k
Total	$1,153k

Background

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection of the Indian Hill-Green River Plant 69kV line was completed in 2017, fifty-three (53) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) 3,283
     Due to the difficulty in obtaining an extended outage, 50% of the fifty-three (53) wood structures will be energized when they are replaced with steel structures. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $140k and the NPVRR by $175k
  2. Alternative #1: Do Nothing NPVRR: ($000s) 4,722
     The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
  3. Alternative #2: Replace with Wood NPVRR: ($000s) 3,672
     The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing fourteen (14) standard steel H-frame structures, thirty-four (34) tangent steel davit arm structures, one (1) steel single pole running corner, four (4) steel single pole dead end structures, and associated hardware and material, and the removal of fifty-three (53) wood structures, and associated hardware and material. Construction is scheduled to begin in February of 2019 and be completed in June of 2019.

Construction Milestones	
July 2018	Engineering and Design
August 2018	Space reserved for steel pole production with manufacturer
November 2018	Steel Poles Ordered
February 2019	Steel Poles Received
February 2019	Line Construction Begins
June 2019	Line Construction Completed

A facility map of the Hillside-Green River Plant 69kV line is shown below:
Total line length: 10.01 miles Total structures in line: 147

[redacted]

- **Project Cost**
  The current total project cost is $2,635k. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**

  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $826k. This project will utilize standard steel structures. The steel structures will be purchased through the Company's steel pole alliance partner. The line construction will be based on continuing contracts from the Company's line contractors.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$737k
Hardware	$89k
Total	$826k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	2,374	-	-	-	2,374
2. Cost of Removal Proposed	262	-	-	-	262
3. Total Capital and Removal Proposed (1+2)	2,635	-	-	-	2,635
4. Capital Investment 2019 BP	1,482	-	-	-	1,482
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,482	-	-	-	1,482
7. Capital Investment variance to BP (4-1)	(892)	-	-	-	(892)
8. Cost of Removal variance to BP (5-2)	(262)	-	-	-	(262)
9. Total Capital and Removal variance to BP (6-3)	(1,154)	-	-	-	(1,154)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$72
Contract Labor:	$1,106
Materials:	$826
Local Engineering:	$181
Burdens:	$211
Contingency:	$239
Reimbursements:	($0)
Net Capital Expenditure:	$2,635

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available for the duration of the project, and approximately 50% of the fifty-three (53) structures will need to be completed with the 69kV line energized.

  Alternative #1 – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

  Alternative #2 – The cost of this alternative assumes the cost of the wood poles is 37% the cost of the steel poles, and that the wood poles would be replaced again in 30 years. The estimated life of the steel poles is 90 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Hillside-Green River Plant 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Hillside-Green River Plant pole replacement project for $2,635k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: January 30, 2019

Project Name: TEP-MOT-Morganfield-Wheatcroft

Total Expenditures: $2,859k
Total Contingency: $260k (10%)

Project Number(s): LI-000092

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Jonathan Meacham

Executive Summary

The Morganfield – Wheatcroft Tap 69 kV line overloads during planning studies and was identified through the 2018 Transmission Expansion Plan (TEP). This project will provide a facility rating increase for the Morganfield – Wheatcroft Tap 69 kV line and eliminate the overloads currently identified. The 2018 TEP identified a need date of 5/30/2019.

The maximum operating temperature (MOT) on the Morganfield – Wheatcroft Tap 69 kV line needs to be increased from 125°F to 135°F in order to alleviate the existing overload condition. To achieve this higher operating temperature, thirty-two (32) spans need corrective action. This work will involve the replacement of thirty-four (34) existing steel towers with thirty-four (34) new steel poles. These structures will raise the height of the line enabling it to meet the National Electric Safety Code (NESC) required clearance when the line is operated at 135°F.

This project was included in the 2019 Business Plan for $2,163k to replace twenty-six (26) structures, with estimated spend of $25k in 2018 and $2,138k in 2019. As scope, timing, and certainty of work has evolved, the estimates have been further refined. The current total project cost is $2,859k, and was approved by the RAC in the 0+12 forecast.

Background

The overload of the Morganfield – Wheatcroft Tap 69 kV line was identified in the TEP and approved by TranServ, the Company's Independent Transmission Organization (ITO).

The Morganfield – Wheatcroft Tap 69 kV line currently consists of 397.5 ACSR (aluminum conductor steel reinforced) with an MOT of 125°F. To eliminate the overload, the MOT on this line section will be increased to 135°F.

During the 90/10 summer peak conditions, an outage of the Morganfield – Sunoco Tap section of the Morganfield – Wheatcroft 69 kV line results in an overload of 104% in the 2019 summer. This overload exists throughout the planning horizon.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) 3,562
       The recommendation is to install thirty-four (34) new steel poles, and remove thirty-four (34) steel towers during a scheduled outage.
    2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
       This alternative puts the customer load at risk and violates the company's Planning Guidelines.
    3. Alternative #2: Replace with Towers NPVRR: ($000s) 4,236
       The next best alternative would be to replace the thirty-four (34) existing steel towers with new steel towers. Towers typically have less deflection (movement) than steel poles, which make them a better application for terminal structures. At the time when these were installed (late 1920s), the use of tubular steel poles in the utility industry had not yet occurred.

Project Description

- **Project Scope and Timeline**
  The scope of work will involve the installation of thirty-four (34) new steel poles, and associated hardware and material, and the removal of thirty-four (34) steel towers, and associated hardware and material. The line construction will be based on continuing contracts from the Company's line contractors. Construction is scheduled to begin in June of 2019 and be completed in September of 2019.

Construction Milestones	
August 2018	Engineering and Design
November 2018	Space Reserved with Steel Pole Manufacturer
February 2019	Steel Poles Ordered
May 2019	Steel Poles Received
June 2019	Line Construction Begins
September 2019	Line Construction Completed

A one-line diagram showing the overloaded line (Morganfield – Wheatcroft Tap 69 kV) and contingency (Morganfield – Sunoco Tap 69 kV) is included below:

[redacted]

A geographical map of the Morganfield-Wheatcroft 69kV line is included below:
Total line length: 30.07 miles Total structures in line: 170

[redacted]

- **Project Cost**
  The total project cost is $2,859k. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**
  Based on the engineering analysis, Transmission Lines has estimated the material packages for construction of this project to be $615k. This project will utilize standard steel structures. The steel structures will be purchased through the Company's steel pole alliance partner. The line construction will be based on continuing contracts from the Company's line contractors.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$550k
Hardware	$65k
Total	$615k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	-	2,367	-	-	2,367
2. Cost of Removal Proposed		492	-	-	492
3. Total Capital and Removal Proposed (1+2)	-	2,859	-	-	2,859
4. Capital Investment 2019 BP	25	2,138	-	-	2,163
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	25	2,138	-	-	2,163
7. Capital Investment variance to BP (4-1)	25	(229)	-	-	(204)
8. Cost of Removal variance to BP (5-2)	-	(492)	-	-	(492)
9. Total Capital and Removal variance to BP (6-3)	25	(721)	-	-	(696)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$96
Contract Labor:	$1,489
Materials:	$615
Local Engineering:	$198
Burdens:	$201
Contingency:	$260
Reimbursements:	($0)
Net Capital Expenditure:	$2,859

- **Assumptions**

Recommendation - This assumes that thirty-four (34) existing steel towers will be replaced with thirty-four (34) new steel poles. An outage must be obtained to complete the project and is scheduled for 2019.

Alternative #1 – Do Nothing - This alternative puts the customer load at risk and violates the Company’s Transmission Planning Guidelines.

Alternative #2 – Replace with Steel Towers – This alternative assumes that thirty-four (34) existing steel towers would be replaced with thirty-four (34) new steel towers during a scheduled outage.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the designated structures in the Morganfield – Wheatcroft Tap 69 kV line, there is risk of losing load in the Morganfield area. Inclement weather which affects site access and working conditions would increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the TEP-MOT-Morganfield-Wheatcroft project for $2,859k to maintain proper operating temperature of 135°F.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: Loudon-Rockwell-Winchester Pole Replacement

Total Capital Expenditures: $3,604k
Total Contingency: $328k (10%)
Total Internal Labor: $85k

Total O&M: $0k

Project Number(s): 156698

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred eighteen (118) wood structures, on the Loudon-Rockwell-Winchester 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of eighty-eight (88) structures identified through inspection in 2017. The replacement of thirty (30) additional adjacent structures is required to accommodate the increased height of the new structures.

Project Milestones	
September 2018	Engineering and Design
October 2018	Space reserved for steel pole production with manufacturer
February 2019	Steel Poles Ordered
April 2019	Steel Poles Received
April 2019	Line Construction Begins
October 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $2,694k to replace one hundred (100) structures. Twelve (12) structures will be replaced as a part of project LI-000083 (TEP-CR-Loudon Avenue-Hume Road) due to the location of the structures. Subsequent to the 2019 BP planning, thirty (30) structures were added to the project scope. In addition, funding in the amount of $241k was included for structure access. The incremental funding of $910k was approved by the RAC in the 0+12 forecast.

Incremental Cost Detail	
18 Additional Structures	$505k
Structures Access	$241k
Reclamation/Damages/Traffic Control	$164k
Total	$910k

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. Two inspections were completed on the Loudon-Rockwell-Winchester 69kV line. A routine climbing was completed in 2016, and a Comprehensive Visual Inspection (CVI) was completed in 2017. From these inspections, eighty-eight (88) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. Thirty (30) additional adjacent structure will also be replaced in order to accommodate the increased height of the new structures

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,042	-	-	-	3,042
2. Cost of Removal Proposed	562	-	-	-	562
3. Total Capital and Removal Proposed (1+2)	3,604	-	-	-	3,604
4. Capital Investment 2019 BP	2,694	-	-	-	2,694
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	2,694	-	-	-	2,694
7. Capital Investment variance to BP (4-1)	(348)	-	-	-	(348)
8. Cost of Removal variance to BP (5-2)	(562)	-	-	-	(562)
9. Total Capital and Removal variance to BP (6-3)	(910)	-	-	-	(910)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Loudon-Rockwell-Winchester 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,489
   The recommendation is to replace all one hundred eighteen (118) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 6,458
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
3. Alternative #2: NPVRR: ($000s) 4,848
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Loudon-Rockwell-Winchester pole replacement project for $3,604k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project LI-000036 Pineville-Rocky Branch Pole Replacement

Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: Pineville-Rocky Branch Pole Replacement

Total Capital Expenditures: $4,509k
Total Contingency: $410k (10%)
Total Internal Labor: $92k

Total O&M: $0k

Project Number(s): LI-000036

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith/John Doll

Brief Description of Project

The proposed project is to replace forty-five (45) wood structures, on Pineville-Rocky Branch 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of forty-five (45) structures identified through inspection in 2017.

Project Milestones	
June 2018	Engineering and Design
October 2018	Space reserved for steel pole production with manufacturer
December 2018	Steel Poles Ordered to Inventory
February 2019	Steel Poles Received to Inventory
February/March 2019	Steel Poles Charged from Inventory
March 2019	Line Construction Begins
July 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $4,629k to replace fifty-six (56) structures. As timing and certainty of work has developed, the estimates have been further refined. The current total project cost is $4,509k.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection was performed on the Pineville-Rocky Branch 69kV circuit. The Gardner Tap inspection was completed in 2015, and the inspection of the main line between Pineville and Rocky Branch line was completed in 2017. A total of fifty-six (56) structures were identified to be in need of replacement in order to ensure the integrity and reliability of this circuit. Forty-five (45) of these structures will be replaced on this project. Six (6) structures were previously completed on the Gardner Tap pole replacement project (LI-158326) in 2018, a tap off the main Pineville to Rocky Branch circuit. The remaining five (5) structures were identified as Line to Ground (LTG) structures and will be replaced in 2019 on project LI-158816.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,652	-	-	-	3,652
2. Cost of Removal Proposed	857	-	-	-	857
3. Total Capital and Removal Proposed (1+2)	4,509	-	-	-	4,509
4. Capital Investment 2019 BP	4,629	-	-	-	4,629
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	4,629	-	-	-	4,629
7. Capital Investment variance to BP (4-1)	978	-	-	-	978
8. Cost of Removal variance to BP (5-2)	(857)	-	-	-	(857)
9. Total Capital and Removal variance to BP (6-3)	120	-	-	-	120

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Pineville-Rocky Branch 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) $5,617
   The recommendation is to replace all one forty-five (45) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) $8,079
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
3. Alternative #2: NPVRR: ($000s) $5,992
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Pineville-Rocky Branch pole replacement project for $4,509k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Combined Project and Contract Investment Proposal

Investment and Contract Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: [redacted] Generator Interconnection Agreement and Project

Contract Authorization Requested: $5,479k (Including $501k of contingency)

Total Capital Expenditures Requested: $5,479k (gross) (Including $501k of contingency and $199k of internal labor); $4,758k net
Total O&M: $0k

Project Number(s): 158933 Interconnection Subs, 158936 Network Subs, and 158937 Network Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), TranServ.

On April 27, 2017 [redacted] (customer) proposed the interconnection of a new 35MW solar generating facility in [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Upgrades that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $5,479k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $721k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $4,758k. The OATT includes a provision to protect LG&E/KU from constructing unnecessary network facilities. The customer must provide LG&E/KU with acceptable security to ensure LG&E/KU is reimbursed for unnecessary network upgrade costs if the generation interconnection is not completed.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $5,479k, which includes a 10% contingency. This contingency matches the level of analysis performed to develop the cost estimate and covers increases in actual costs beyond the estimate. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if the customer desired to move forward with the LGIA; however, it will be included in the 2020 BP if the LGIA is executed.

<u>Why is the project needed? What if we do nothing?</u>

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in [redacted] and interconnect with LG&E/KU's Cynthiana EK Tap to Millersburg 69kV line. This project will have minimal impact on reliability and/or the customer experience.

[redacted]

[redacted]

[redacted]

Contract Bid Summary

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreeement with the Customer in early May 2019. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement is executed). Once the project is started, it will take approximately twenty-four months until construction is complete and the unit achieves commercial operation status.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates	-	-	3,858	1,120	-	-	4,978
Contingency Amount Requested	-	-	389	112	-	-	501
Gross contract authority requested	-	-	4,247	1,232	-	-	5,479

Interconnection Reimbursement	-	-	(541)	(180)	-	-	(721)
Net contract	-	-	3,706	1,052	-	-	4,758
Network Upgrade Security Payment	-	-	(4,758)	4,758	-	-	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	-	-	4,142	1,232	5,374
2. Cost of Removal Proposed	-	-	105	-	105
3. Total Capital and Removal Proposed (1+2)	-	-	4,247	1,232	5,479
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	-	(4,142)	(1,232)	(5,374)
8. Cost of Removal variance to BP (5-2)	-	-	(105)	-	(105)
9. Total Capital and Removal variance to BP (6-3)	-	-	(4,247)	(1,232)	(5,479)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($000s)	**158933 [redacted] Interconnection Subs**	**158936 [redacted] Network Upg Subs**	**158937 [redacted] Network Upg Lines**	**Total**
Company Labor	30	$159	$10	$199
Contract Labor	$306	$1,653	$254	$2,213
Materials	$212	$1,378	$158	$1,748
Contingency	$66	$385	$50	$501
Burdens	$107	$634	$77	$818
Gross Capital Expenditure	$721	$4,209	$549	$5,479
Reimbursement	($721)	$0	$0	($721)
Net Capital Expenditure	$0	$4,209	$549	$4,758
Contingency %	10%	10%	10%	10%

Risks

- Facilities are not built in time by LG&E/KU. LG&E/KU may be responsible for liquidated damages in accordance with Section 5.3 of the LGIA if the work required by LG&E/KU is not completed by the mutually acceptable dates determined by LG&E/KU and the Customer.
- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.
- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Upgrades. If the commercial operations date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $6,339
   Pursue execution of the LGIA with [redacted], as required under the OATT. If LGIA is executed by [redacted], proceed with construction of transmission interconnection facilities and network upgrades, as granted by the ITO, [redacted]
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.
3. Alternative #2: Not Applicable NPVRR: ($000s) N/A
   To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed similarly to the previously approved project and executed LGIA with [redacted]. Deviating from the [redacted] project is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] LGIA and project for $5,479k to satisfy its Open Access Transmission Tariff obligations.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] Large Generator Interconnection Agreement contract for $5,479k with [redacted].

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Combined Project and Contract Investment Proposal

Investment and Contract Proposal for Investment Committee Meeting on: April 24, 2019 Project Name: [redacted] to KU West Shelby Interconnection Contract Name: [redacted] Interconnection Agreement (IA) and Contribution In Aid of Construction Agreement (CIAC) Contract Authorization Requested: \$5,708k (Including \$463k of contingency) Total Capital Expenditures Requested: \$5,097k (Including \$463k of contingency and \$132k of internal labor), net \$0k Total O&M: \$0k Project Number(s): 159001 & 159597 (Subs) and 158961 (Lines) Business Unit/Line of Business: Transmission Prepared/Presented By: Chris Balmer

Brief Contract/Project Description

This proposal requests contract and project approval for a new transmission interconnection between LG&E/KU and [redacted]. [redacted] requested the new interconnection and has agreed to pay the actual construction costs which have been grossed up for taxes as agreed upon in the CIAC. Upon execution, the CIAC will be filed with FERC.

The project consists of a 69kV three-breaker ring bus switching station, to be constructed by LG&E/KU, at a point approximately 600 feet north of the Simpsonville-Shelbyville 69kV line on the north side of US 60 in Shelby County. The construction timeline is estimated to commence in September 2019 and be completed around June 2020. [redacted] will construct the necessary 69kV line from their Bekaert station to the new interconnection point.

LG&E/KU have performed all necessary studies and estimated construction costs of \$5,097k, which includes \$463k of contingency. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if [redacted] desired to move forward with the interconnection; however, it will be included in the 2020 BP assuming internal approvals are obtained and applicable agreements are executed with [redacted].

In order to provide the requested interconnection and properly document the cost allocation responsibility, this request is for Investment Committee approval of the IA, CIAC and project approval of up to \$5,097k, which includes a 10% contingency of \$463k. The CIAC includes tax gross up of \$611k in addition to the project cost.

<u>Why is the project needed? What if we do nothing?</u>

[redacted] has requested the construction of the new interconnection to enhance the reliability of several distribution loads that are currently served from and relying solely on a radial [redacted] 69kV transmission line. The distribution loads that are currently served from the [redacted] 69kV line *do not* require the new interconnection; rather, the interconnection is being requested to improve what is currently sufficient service from [redacted]s own transmission system and facilities. FERC's general policies contemplates transmission interconnections to be accommodated, with the interconnection parties agreeing on the cost and compensation related to the interconnection, as is the case here. Since the new requested interconnection does not result in adverse impacts to the LG&E/KU transmission system and [redacted] has agreed to pay appropriate cost, LG&E/KU does not have a reasonable basis to deny the request.

· **Project Scope and Timeline**	
Description	**Date**
Engineering Start(Subs) –	5/22/2019
Engineering Complete (Sub) –	12/17/2019
Engineering Start (Lines)	11/15/2019
Engineering Complete (Lines)	12/4/2019
Civil Construction complete (Subs)	9/10/2019
Below Grade Construction Complete (Subs)	4/20/2020
Above Grade Construction Complete (Subs)	5/4/2020
Protection and Control Complete (Subs)	6/17/2020
Line Construction Complete	2/24/2020
In Service date	6/17/2020

<u>Contract Bid Summary</u>

- Once [redacted] agrees to the terms in the IA and CIAC agreement, this project will be bid as required.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates	4,311	323	-	-	-	-	4,634
Contingency amount requested	430	33	-	-	-	-	463
Gross Capital	4,741	356	-	-	-	-	5,097
Tax Gross Up	611	-	-	-	-	-	611
Gross contract authority requested	5,352	356	-	-	-	-	5,708
Reimbursement	(5,352)	(356)	-	-	-	-	(5,708)
Net contract	-	-	-	-	-	-	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	4,741	339	-	-	5,080
2. Cost of Removal Proposed	-	17	-	-	17
3. Total Capital and Removal Proposed (1+2)	4,741	356	-	-	5,097
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(4,741)	(339)	-	-	(5,080)
8. Cost of Removal variance to BP (5-2)	-	(17)	-	-	(17)
9. Total Capital and Removal variance to BP (6-3)	(4,741)	(356)	-	-	(5,097)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($000s)	159001 Network Upg Subs	158961 Network Upg Lines	159597 Land Acquisition	Total
Company Labor	$120	$12	$0	$132
Contract Labor	$1,603	$182	$0	$1,785
Materials	$1,612	$87	$0	$1,699
Land	$0	$0	$250	$250
Contingency	$402	$33	$28	$463
Burdens	$689	$51	$28	$768
Gross Capital Expenditure	$4,426	$365	$306	$5,097
Reimbursement	($4,426)	($365)	($306)	($5,097)
Net Capital Expenditure	$0	$0	$0	$0
Contingency %	10%	10%	10%	10%
Tax Gross Up	$565	$46	$0	$611

The Tax Gross Up will be recorded as revenue on the Income Statement.

Risks

There are minimal financial risks to LG&E/KU associated with this project. While the customer has been provided with a good faith estimate, the amount LG&E/KU will be reimbursed will be based on the actual cost of construction.

[redacted] has requested an in service date of June 1st, 2020. Delays in acquiring the property and obtaining the necessary permits could impact meeting this date. In the absence of a geotechnical report, assumptions were made regarding the subsurface conditions of the site. Should the geotechnical report reveal that the site conditions are unfavorable for the construction of a substation, then the project schedule will be compromised and the overall cost of the project will increase, which [redacted] would be contractually required to pay.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) N/A
   Pursue execution of the Interconnection Agreement and Contribution In Aid of Construction Agreement. If executed, construct the project as outlined above. [redacted] will reimburse LG&E/KU's cost; therefore, there is not a revenue requirement for LG&E/KU customers.
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   Since there are no adverse impacts to the LG&E/KU transmission system as a result of the interconnection and [redacted] will pay for actual costs incurred by LG&E/KU for the project, doing nothing is not considerd a viable alternative. Under these circumstances, if [redacted] files a FERC complaint against LG&E/KU, it is believed [redacted] will prevail.

3. Alternative #2: Not applicable NPVRR: ($000s) N/A
   No other alternative was seriously evaluated since [redacted] agreed to pay for the costs associated with the interconnection design suggested by LG&E/KU.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Interconnection Agreement, Contribution In Aid of Construction Agreement amounts of $5,708k, and the project for $5,097k.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] to KU West Shelby Interconnection Agreement and CIAC Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] to KU West Shelby Interconnection Agreement contract and CIAC Agreement for $5,708k with [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal Project LI-159181 KU Park-Greasy Creek-Bimble Pole Replacement

Investment Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: KU Park-Greasy Creek-Bimble Pole Replacement

Total Capital Expenditures: $2,282k
Total Contingency: $207k (10%)
Total Internal Labor: $66k

Total O&M: $0k

Project Number(s): LI-159181

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Dionisio/Adam Smith

Brief Description of Project

The proposed project is to replace seventeen (17) wood structures, on the KU Park-Greasy Creek-Bimble 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of sixteen (16) structures identified through inspection in 2018. The replacement of one (1) additional adjacent structure is required to accommodate the increased height of the new structures.

Project Milestones	
December 2018	Engineering and Design
January 2019	Space reserved for steel pole production with manufacturer
May 2019	Steel Poles Ordered
July 2019	Steel Poles Received
August 2019	Line Construction Begins
October 2019	Line Construction Completed

This project was not included in the 2019 Business Plan (BP). A climbing inspection was completed in August of 2018, subsequent to the 2019 BP planning. The total project cost of $2,282k was approved by the RAC in the 2+10 forecast.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine climbing inspection was completed in 2018, and sixteen (16) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. One (1) additional adjacent structure will also be replaced in order to accommodate the increased height of the new structures.

The scope of work consists of installing eleven (11) steel H-Frame structures, four (4) steel three-pole running corners, and two (2) three-pole dead end structures. The four (4) running corner structures and two (2) dead end structures are drivers for the higher than typical per structure replacement cost on this project. In addition, funding for road building and vegetation clearing to gain access to the structures is contributing to the higher than typical per structure replacement cost.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,967	-	-	-	1,967
2. Cost of Removal Proposed	316	-	-	-	316
3. Total Capital and Removal Proposed (1+2)	2,282	-	-	-	2,282
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(1,967)	-	-	-	(1,967)
8. Cost of Removal variance to BP (5-2)	(316)	-	-	-	(316)
9. Total Capital and Removal variance to BP (6-3)	(2,282)	-	-	-	(2,282)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the KU Park-Greasy Creek-Bimble 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,843
   The recommendation is to replace all seventeen (17) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 3,997
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
3. Alternative #2: NPVRR: ($000s) 3,760
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Greasy Creek-Bimble pole replacement project for $2,282k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: Nebo-Wheatcroft Crt Pole Replacement

Total Capital Expenditures: $2,970k
Total Contingency: $270k
Total Internal Labor: $96k

Total O&M: $0k

Project Number(s): LI-159178

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Anthony Mount/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-four (34) structures on the Nebo-Wheatcroft 69kV line during a scheduled outage. Thirty-one (31) structures were identified through inspection in 2018. Three (3) additional adjacent structures will be replaced to support the project design.

The scope of work includes replacement of thirty-three (33) existing wood structures with new steel structures, and the replacement of one (1) existing wood structure with a new wood structure. In addition, one (1) existing platform switch will be replaced with two (2) new one-way switches at the Providence East tap point.

To ensure service is maintained at the Providence East and Barnhill substations throughout project construction, replacement of twenty-three (23) defective poles and three (3) existing poles will be accomplished by constructing 1.6 miles of 69kV line within existing easements and parallel to the existing line. A portable substation will be required to maintain service at the Providence East and Barnhill substations during construction. In addition, eight (8) defective poles are being replaced in other sections of this line.

Project Milestones	
January 2019	Engineering and Design
January 2019	Space reserved for steel pole production with manufacturer
April 2019	Standard Steel Structures Ordered to Inventory
May 2019	Standard Steel Structures Received to Inventory
June 2019	Custom Steel Structures Ordered

July 2019	Custom Steel Structures Received
August 2019	Standard Steel Structures Charged from Inventory
September 2019	Line Construction Begins
December 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) under the K9-2019 pole replacement blanket to replace twelve (12) structures. Subsequent to the 2019 BP planning, twenty-two (22) structures were added to the project scope. The total project cost of $2,970k was approved by the RAC in the 2+10 forecast.

Why is the project needed? What if we do nothing?

The Nebo-Wheatcroft 69kV line contains three hundred eighteen (318) structures along the 20.9 mile line. A PSC inspection was completed on this line in 2017, and a Comprehensive Visual Inspection (CVI) was completed on this line in 2018. From these inspections, twelve (12) structures were identified as priority defective replacements, and 155 additional structures were identified as defective:

- Two (2) priority defective poles and thirteen (13) defective poles were identified on the 1.1 mile radial tap off the Nebo-Wheatcroft line out of the 17 poles that feeds the Providence East Substation.
- Two (2) priority defective poles and six (6) defective poles were identified on the 0.5 mile section of the Nebo-Wheatcroft line serving the Barnhill substation.
- Eight (8) priority defective poles were identified in other sections of the Nebo-Wheatcroft line.

[redacted]

To ensure service is maintained at the Providence East and Barnhill substations throughout project construction, replacement of twenty-three (23) defective poles and three (3) existing poles will be accomplished by constructing 1.6 miles of 69kV line within existing easements and parallel to the existing line. This parallel line will replace the 1.6 mile section of the existing line and the twenty-three (23) defective poles. A portable substation will be required to maintain service at the Providence East and Barnhill substations during construction. The map below details the 1.6 mile section that is being replaced.

[redacted]

A second pole replacement project will be completed in 2020 (PR Nebo-Wheatcroft 157635) to replace the remaining one hundred eighteen (118) rejected structures.

Following the pole replacement project, a conductor replacement project will also be completed in 2020 (CR Nebo-Providence East LI-158946) on this circuit. This project will replace 3.70 miles of 2/0 ACSR conductor and the remaining eighteen (18) rejected structures. The one (1) pole being replaced now with a wood pole will be replaced with steel as part of the reconductor project.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,559	-	-	-	2,559
2. Cost of Removal Proposed	411	-	-	-	411
3. Total Capital and Removal Proposed (1+2)	2,970	-	-	-	2,970
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(2,559)	-	-	-	(2,559)
8. Cost of Removal variance to BP (5-2)	(411)	-	-	-	(411)
9. Total Capital and Removal variance to BP (6-3)	(2,970)	-	-	-	(2,970)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions. The total project cost of $2,970k was approved by the RAC in the 2+10 forecast.

Risks

Without the proposed replacement of the priority poles on the Nebo-Wheatcroft 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,701
   The recommendation is to replace all thirty-four (34) wood structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 4,853
   The alternative of do nothing would result in replacing the thirty-one (31) rejected poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
3. Alternative #2: NPVRR: ($000s) 4,606
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a

recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

4. Alternative #3: Total Line Rebuild NPVRR: ($000s) 31,141
   A total rebuild of the line has an estimated NPVRR of $31,141k, compared to the three projects identified for this line which have an estimated NPVRR of $13,994k. Based on the current estimated value of the projects, completing the three projects as planned is the least cost alternative when compared to cost of a total line rebuild.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Nebo-Wheatcroft Crt pole replacement project for $2,970k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: May 29, 2019

Project Name: Dorchester Control House Replacement

Total Capital Expenditures: $4,580k (Including $420k of contingency including $160k of internal labor)

Total O&M: $0k

Project Number(s): SU-000324

Business Unit/Line of Business: Transmission

Prepared/Presented By: Brent Birchell

Brief Description of Project

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Dorchester substation has Transmission facililities operating at 161 kV, and 69 kV. This substation was originally placed in service in 1940. The earliest 69 KV asset was installed circa 1965 and the earliest 161 kV was installed in 1976. This substation is part of the Bulk Electric System (BES) backbone in the Virginia service territory. The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc)
- Replace Substation Insulators – Eleven sets of cap and pin insulators will be replaced.
- Replace Substation Line Arresters – Two sets of 161kV and four sets of 69kV arresters will be replaced.
- Replace Coupling Capacitors – Two 161kV coupling capacitors will be replaced as well as associated power line carrier equipment at the three remote termninals of the 161 KV lines.

For the above mentioned TSIP replacements identified, see Appendix; Exhibits A through E for a switching diagram and a substation overview.

Major equipment at this location include a 161/69 kV, 93 MVA transformer; 161 and 69 kV breakers, and two control houses.

Why is the project needed? What if we do nothing?

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

"System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

The control house replacement is being accelerated from the timing in the 2019 BP. The 69kV Lancaster Control House (project # SU-000405) was planned for replacement in 2019-2020 in the 2019 BP, but that project was replaced with the Dorchester Control House in an effort to meet NERC issued guidelines for a target rate of mis-operations on the BES. The Lancaster Control House replacement was moved to 2021-2022. Additonally, work at the Dorchester substation was aggregated to reduce the cost associated with mobilizing and demobilizing crews. As shown below in the alternative project, savings to the customer are realized by bundling work at a station and minimizing the number of times crews are mobilizedfor specific asset replacements over time. The projects that were included in the 2019 BP for work at Dorchester are SU-000104 ($126k-2018), SU-000396 (249k 2019-2020) and SU-000324 (1,810K 2021-2022). Also, there was additional scope included in the project during the site visit and preliminary work for the project.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	454	4,097	-	-	4,551
2. Cost of Removal Proposed	-	29	-	-	29
3. Total Capital and Removal Proposed (1+2)	454	4,125	-	-	4,580
4. Capital Investment 2019 BP	-	-	725	885	1,610
5. Cost of Removal 2019 BP	-	-	90	110	200
6. Total Capital and Removal 2019 BP (4+5)	-	-	815	995	1,810
7. Capital Investment variance to BP (4-1)	(454)	(4,097)	725	885	(2,941)
8. Cost of Removal variance to BP (5-2)	-	(29)	90	110	172
9. Total Capital and Removal variance to BP (6-3)	(454)	(4,125)	815	995	(2,770)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipement targeted in this project can also require remote clearing of the fault.
- Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the BES.

- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transfomers on the system and other equipement. Proactive replacement of this equipment will minimize the potential of this incremental damage.
- Environmental Impacts: As represented in the TSIP, failed equipement, such as transformers, can result in large financial impacts to the company due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. It is not anticipated that the control houses being replaced by this project will be demolished as part of this project. Those control houses will be abandoned in place and retired on a separate project after this work is complete.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,994

2. Alternative #1: No Control house/Multiple Year work NPVRR: ($000s) 6,484
   Do not install a new control house. Complete the other work detailed in the IP over a period of several years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or more times. Also, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability. Finally, a new control house is much preferred over updating the equipment in the existing control house and replacing the equipment over in the existing structure. The structure is deteriorating and will require additional maintenance. The new relays will have a life span of 20+ years and the existing structure has already reached the end of its expected life. The new relays should be installed in a modern building with a life expectancy greater than the new relays to be installed.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   Do nothing. This is not a viable alternative based on the risks to the system listed above

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester Control House project for $4,580k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix

Exhibit A: Dorchester Switching Diagram

[redacted]

Exhibit B: D[redacted]ugh

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Exhibit C: Arnold Switching Diagram

[redacted]

CONFIDENTIAL INFORMATION REDACTED

Exhibit D: Imboden Switching Diagram

[redacted]

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Exhibit E: Pocket [redacted] gh

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: May 29, 2019

Project Name: Winchester Control House, Relay, Breaker, & Arrester Replacements

Total Capital Expenditures: $2,570k (Including $113k of contingency and $236k of internal labor)

Total O&M: $0k

Project Number(s): SU-000055

Business Unit/Line of Business: Transmission

Prepared/Presented By: Brent Birchell

Brief Description of Project

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Winchester substation has Transmission facililities operating at 69 kV. This substation was originally placed in service in 1959. This substation is part of the network backbone in the Winchester area and serves multiple distribution substations serving many industrial customers. The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc)
- Replace Substation Breakers: Three 69 kV oil-filled circuit breakers removed and SF6 insulated breakers will be installed.
- Replace Substation Line Arresters – 15 sets of 69kV arresters will be replaced.

[redacted]

Why is the project needed? What if we do nothing?

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

"System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

There is an increase in capital spending in 2020 due to additional scope (15 sets of arresters) added during the site visit and preliminary work for the project. As shown below in the alternative project, savings to the customer are realized by bundling work at a station rather than mobilizing and demobilizing crews for specific asset replacements over time.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	205	2,290	-	-	2,495
2. Cost of Removal Proposed	-	75	-	-	75
3. Total Capital and Removal Proposed (1+2)	205	2,365	-	-	2,570
4. Capital Investment 2019 BP	187	1,638	-	-	1,824
5. Cost of Removal 2019 BP	19	214	-	-	233
6. Total Capital and Removal 2019 BP (4+5)	205	1,852	-	-	2,057
7. Capital Investment variance to BP (4-1)	(19)	(652)	-	-	(671)
8. Cost of Removal variance to BP (5-2)	19	139	-	-	158
9. Total Capital and Removal variance to BP (6-3)	0	(513)	-	-	(513)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Completing the project involves risk related to high voltage substation construction work.
- Not completing the project decreases the reliability of the lines and substations discussed in this document.
- Delaying this project exposes the system to the continuing risk of impacts from other potential transmission failures.
- Environmental: There is also a risk due to asbestos potentially in the control cable and other material in the control house. It is not anticipated that the control houses being replaced by this project will be demolished as part of this project. This control house will be abandoned in place and retired on a separate project after this work is complete.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,798

2. Alternative #1: Complete over multiple years NPVRR: ($000s) 4,699
   Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or three times. Also, delaying the work leaves LKE open to failure of

the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
This is not a viable alternative. The system is experiencing occasional, unpredictable failures of the breakers, line relaying and remote terminal unit (RTU) types installed at this station. Similar failures will eventually happen here if the equipment is not replaced.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Winchester Control House, Relay, Breaker and Arrester Replacement project for $2,570k to improve system reliability.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

______________________________	______________________________
Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

<u>Appendix:</u>

Exhibit A: Winchester Switching Diagram

[redacted]

Exhibit B: Winchester Substation Overview

[redacted]

Investment and Contract Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: [redacted] Solar Generator Interconnection Project
Contract Name (Good/Service): [redacted] Solar Generator Interconnection Agreement

Contract Authorization Requested: $2,466k (Including $603k of contingency)

Total Capital Expenditures Requested: $2,466k (Including $603k of contingency and $122k of internal labor)
Total O&M: $0k

Project Number(s): 159803
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted]

On August 8, 2017 [redacted] (Customer) proposed the interconnection of a new 100MW solar generating facility in [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Upgrades that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $2,466k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which make up the entirety of the $2,466k total. This interconnection does not require any Network Facilities.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up to $2,466k, which includes a 32% contingency. This contingency matches the level of analysis performed to develop the cost estimate and covers increases in actual costs beyond the estimate. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if the Customer desired to move forward with the LGIA; however, it will be included in the proposed 2020 BP with the assumption that the LGIA will be executed.

<u>Why is the project needed? What if we do nothing?</u>
LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The Customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in [redacted] and interconnect with LG&E/KU's existing 138kV Green River substation. As required by the established and approved generation interconnection criteria, the Customer will interconnect as designed in Figure 1 and will construct and own the approximately 1.7 mile long 138kV lead line from the generating plant to the Green River substation. This project will have minimal impact on reliability and/or the customer experience.

[redacted]

[redacted]

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[redacted]

Contract Bid Summary

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreeement with the Customer in early July 2019. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement is executed). Once the project is started, it will take approximately twenty-four months until construction is complete and the unit achieves commercial operation status. LG&E/KU will be reimbursed for actual construction costs upon completion of the project.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates (including contingency embedded in contract)	-	-	-	130	1,916	3	2,049
Contingency amount requested (in addition to contingency in contract)	-	-	-	-	-	417	417
Gross contract authority requested	-	-	-	130	1,916	420	2,466
Interconnection Reimbursement	-	-	-	-	-	(2,466)	(2,466)
Network Upgrade Prepayment	-	-	-	-	-	-	-
Network Upgrade Refund	-	-	-	-	-	-	-
Net contract	-	-	-	130	1,916	(2,046)	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2022	2023	2024	Post 2024	Total
1. Capital Investment Proposed	130	1,916	420	-	2,466
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	130	1,916	420	-	2,466
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(130)	(1,916)	(420)	-	(2,466)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(130)	(1,916)	(420)	-	(2,466)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Facilities are not built in time by LG&E/KU. LG&E/KU may be responsible for liquidated damages in accordance with Section 5.3 of the LGIA if the work required by LG&E/KU is not completed by the mutually acceptable dates determined by LG&E/KU and the Customer.
- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the contingency amount of the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The Customer is required to pay the actual cost of the Transmission Interconnection Facilities.
- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities. If the commercial operations date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,681
   Pursue execution of the LGIA with Customer as required under the OATT. If LGIA is executed by Customer, proceed with construction of transmission interconnection facilities, as granted by the ITO, [redacted]. The NPVRR above is for the Gross capital requested, the NPVRR is $0 on a net project basis.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.

3. Alternative #2: Not Applicable NPVRR: ($000s) N/A
   To provide non-discriminatory generation interconnection service, the recommendation is designed to meet the approved generator interconnection criteria and is proposed similarly to the previously approved projects and executed LGIAs with [redacted] and [redacted]. Deviating from the approved criteria and the [redacted] and [redacted] projects is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Interconnection Agreement and the project for $2,466k.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted]

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] [redacted]r Interconnection Agreement contract for $2,466k with [redacted]

Sourcing Leader [If applicable; the approvers for this table can be modified as needed]		Proponent/Team Leader	
Supplier Diversity Manager [If applicable]		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain David Cosby	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: Proactive Control House - Middlesboro

Total Capital Expenditures: $2,309k (Including $210k of contingency including $111k of internal labor)

Total O&M: $0k

Project Number(s): SU-000002

Business Unit/Line of Business: Transmission

Prepared/Presented By: Brent Birchell

Brief Description of Project

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Middlesboro 1 substation has Transmission facilities operating at 69 KV. This substation was originally placed in service in 1958. The earliest 69 KV asset was installed circa 1960. This substation is part of the network backbone in the Pineville area and serves multiple distribution substations.

The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc.)
- Install Station Service Transformer – One 69kV station service voltage transformer will be installed.

[redacted]

Major equipment at this location include 69 KV breakers (which were replaced in 2016), a 69 KV capacitor bank, and 1 control house.

Description	Date
Preliminary Funding for Project Approved	December 2018
Full Funding for Project Approved	June 2019
Major Materials Ordered	June 2019
Major Materials Received	January 2020
Project Complete	Dec 2020

Why is the project needed? What if we do nothing?

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

"System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

This project was originally opened for $279k during December 2018 for preliminary engineering and is being revised for full funding based on the results of preliminary engineering. There is an increase in capital spending in 2020 that accounts for additional scope added to the project during the site visit and preliminary work for the project. As shown below in the alternative project, savings to the company are realized by doing more work at a station rather than mobilizing and demobilizing crews for specific asset replacements over time. This project was approved by the RAC in the 4+8 forecast.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	480	1,797	-	-	2,276
2. Cost of Removal Proposed	-	33	-	-	33
3. Total Capital and Removal Proposed (1+2)	480	1,829	-	-	2,309
4. Capital Investment 2019 BP	642	700	-	-	1,342
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	642	700	-	-	1,342
7. Capital Investment variance to BP (4-1)	162	(1,097)	-	-	(934)
8. Cost of Removal variance to BP (5-2)	-	(33)	-	-	(33)
9. Total Capital and Removal variance to BP (6-3)	162	(1,129)	-	-	(967)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.

Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the Bulk Electric System (BES).

Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental damage.

Environmental Impacts: There is a risk of asbestos that has been identified with control cables and certain parts of pre-1980 control houses. Existing control cables and the control house will be abandoned in place. These assets will be removed on another project after the work at a later date.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,540

2. Alternative #1: Stagger replacements NPVRR: ($000s) $3,089
   2019 - Install new transclosure to contain DFR and RTU. Install SSVT, trench, battery equipment, new distribution panels, and various communication upgrades. Remove arresters and insulators. Upgrade ground grid.
   2020 - Replace bus differential relays and capacitor bank relays, add slip over CTs.
   2021 - Replace remaining equipment including five remaining line relay panels.

   Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or three times. In addition, delaying the work leaves LKE open to failure of the equipment, which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do nothing NPVRR: ($000s) N/A
   This is not a viable alternative. The system is experiencing occasional, unpredictable failures of the line relaying and RTU types installed at this station. Similar failures will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Proactive Control House Middlesboro project for $2,309k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

CONFIDENTIAL INFORMATION REDACTED

Appendix

Exhibit A: Middlesboro Switching Diagram

[redacted]

Exhibit B: Middlesboro Substation Overview

[redacted]

Investment Proposal for Investment Committee Meeting on: July 31, 2019

Project Name: Proactive Control House Replacement - Canal

Total Capital Expenditures: $9,636k (Including $851k of contingency and $400k of internal labor)

Total O&M: $0k

Project Number(s): SU-000370

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Brent Birchell

Brief Description of Project

Consistent with the scope of the Transmission System Improvement Plan (TSIP) this project is an aggregation of several system integrity programs to address assets in need of replacement at one of LG&E's oldest electrical substations. The Canal substation has Transmission facilities operating at 138 kV and 69 kV. This substation was originally placed in service in 1939. The earliest 69 KV asset was installed circa 1959 and the earliest 138 kV was installed in 1957. This substation serves as part of the backbone that both directly feeds the downtown Louisville network and is interconnected with other stations that are sources to this area. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). One remote relaying panel will be replaced at the Madison and Paddys West Substations, and two remote relaying panels will be replaced at the Ohio Falls Substation. The existing elecromechanical type control and protective relay systems will be replaced with modern, microprocessor based systems that will ensure reliable operation as well as provide added data for analysis of system events.
- Replace Substation Breakers - Eight (8) 69kV and two (2) 138KV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release. The Canal Substation is adjacent to the Ohio River.
- Replace Substation Disconnect Switches – Fourteen (14) 69kV and six (6) 138kV high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age where failure is common, often times during operation.
- Replace Substation Insulators – Ninety-one (91) 69KV underhung and cantilever cap & pin type insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

- Install Substation Line Arresters – twenty-one (21) single phase surge arresters will be installed. Surge arrestors are being installed to provide open breaker protection due to lightning strikes. The exsting substation uses an outdated spark gap protection system mounted on the disconnect switches that are being removed.

[redacted]

<u>Why is the project needed? What if we do nothing?</u>
The project is needed to modernize this substation and ensure reliable operation far into the future. The existing equipment and systems are 50-60+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

<u>Budget Comparison & Financial Summary</u>
There is an increase in the cost compared to the original budget estimate due to additional scope required to accomplish the objectives of the program that was determined during the preliminary engineering work for the project as well as a more accurate estimate based on bids. Multiple asset replacements will be aggregated on this project to reduce the cost associated with mobilizing and demobilizing crews. As shown below in the alternative project, savings to are realized by bundling work at a station and minimizing the number of times crews are mobilized for specific asset replacements over time. This project was approved by the RAC in 2019 6+6 Forecast.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	258	1,275	7,569	42	-	9,144
2. Cost of Removal Proposed	-	-	492	-	-	492
3. Total Capital and Removal Proposed (1+2)	258	1,275	8,061	42	-	9,636
4. Capital Investment 2019 BP	258	372	1,600	-	-	2,230
5. Cost of Removal 2019 BP	-	46	229	-	-	275
6. Total Capital and Removal 2019 BP (4+5)	258	418	1,829	-	-	2,505
7. Capital Investment variance to BP (4-1)	0	(903)	(5,969)	(42)	-	(6,914)
8. Cost of Removal variance to BP (5-2)	-	46	(263)	-	-	(217)
9. Total Capital and Removal variance to BP (6-3)	0	(857)	(6,232)	(42)	-	(7,131)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-	-

Risks

- Contracting Strategy – An EPC contract strategy has been used for this project and the costs are reflected above.
- Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the Bulk Electric System (BES).
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. Materials suspected to contain asbestos will be managed by qualified personnel.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 10,072

2. Alternative #1: NPVRR: ($000s) 10,724
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening in the near future. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and C&P insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Proactive Control House Canal project for $9,636k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

CONFIDENTIAL INFORMATION REDACTED

Appendix:

Exhibit A: Canal Switching Diagram

[redacted]

CONFIDENTIAL INFORMATION REDACTED

Exhibit B: Canal Substation Overview

[redacted]

Investment Proposal for Investment Committee Meeting on: August 29, 2019

Project Name: Bimble-London Pole Replacement

Total Capital Expenditures: $2,909k (Including $262k of contingency and $48k of internal labor)

Total O&M: $0k

Project Number(s): 157641

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Mina/Adam Smith

Brief Description of Project

The proposed project is to replace twenty-seven (27) structures identified through inspection in 2018 on the Bimble-London 69kV line during a scheduled outage. The scope of work includes replacement of twenty-seven (27) existing wood structures with new steel structures.

Project Milestones	
April 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
November 2019/January 2020	Steel Poles Received
January 2019	Line Construction Begins
March 2020	Line Construction Completed

This project was included in the 2019 Business Plan (BP).

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A PSC inspection was completed in 2018, and twenty-seven (27) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing twenty-five (25) steel H-Frame structures, one (1) steel three-pole running corner, and one (1) three-pole dead end structure.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	94	2,438	-	-	2,533
2. Cost of Removal Proposed	-	377	-	-	377
3. Total Capital and Removal Proposed (1+2)	94	2,815	-	-	2,909
4. Capital Investment 2019 BP	390	2,799	-	-	3,189
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	390	2,799	-	-	3,189
7. Capital Investment variance to BP (4-1)	296	361	-	-	657
8. Cost of Removal variance to BP (5-2)	-	(377)	-	-	(377)
9. Total Capital and Removal variance to BP (6-3)	296	(16)	-	-	280

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Bimble-London 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,409
   The recommendation is to replace all twenty-seven (27) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 5,212
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on

environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 4,100
The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bimble-London pole replacement project for $2,909k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: August 29, 2019

Project Name: Farmers-Spencer Road Conductor Replacement

Total Capital Expenditures: $15,896k (Including $1,444 of contingency and $436k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - 152706
Distribution Operations – 20XMUB366

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

The proposed project is to replace 13.5 miles of overhead transmission line with conductor that is over 80 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent event occurring in 2019. Kentucky Utilities Salt Lick Tap serves over 900 customers with 5.1 MVA of load. In addition, the [redacted] interconnection at the Cave Run Tap serves 2.2 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Morehead and Mt. Sterling areas.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 13.5 mile section of 2/0 aluminum conductor steel reinforced (ACSR) conductor from structure 264 to structure 482 in the Salt Lick-Spencer Road section of the Farmers-Spencer Road 69kV line with 397 26/7 ACSR, and new optical ground wire (OPGW) will be installed. In addition, two hundred twenty-three (223) wood structures will be replaced with one hundred thirty-two (132) new steel structures. The proposed project utilizes a new design which optimizes the structure placement, removing ninety-one (91) structures. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

Project Milestones – Transmission Lines	
July 2018-July 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
January 2020	Steel Poles Received
January 2020	Line Construction Begins
March 2021	Line Construction Completed

Project Milestones – Distribution Operations	
October 2019	Engineering and Design
November 2019	Materials Ordered
January 2020	Materials Delivered
January 2020	Construction Start
April 2020	Construction Completed

The total project cost is $15,896k ($15,881k Transmission Lines, $15k Distribution Operations). This project was included in the 2019 Business Plan (BP) for $11,993k, including an estimated spend of $33k in 2018, $200k in 2019, $5,046k in 2020, $5,748k in 2021, and $966k in 2022. As the scope, timing and certainty of work has evolved, the estimates have been further refined, with current estimates of $29k in 2018, $722k in 2019, $6,202k in 2020 and $8,943k in 2021. 2019 spend was approved by the Corporate Resource Allocation Committee. 2020 spend is included in the proposed 2020 BP. Spend in 2021 is included in the proposed 2020 BP for $7,674k. Project 147248 (TEP-MOT-Waitsboro-Union UW) was reduced $1,269k to fund difference in 2021.

	Transmission Lines	Distribution Operations	Total
Total 2018	$29.1k	$0k	$29.1k
Total 2019	$722.3k	$0k	$722.3k
Total 2020	$6,186.2k	$15.4k	$6201.6k
Total 2021	$8,943.4k	$0k	$8,943.4k
Project Total	$15,881k	$15k	$15,896k
Contingency	10%	0%	

Why is the project needed? What if we do nothing?

The existing 13.5 mile section of 69kV line between the Farmers and Spencer Road substations contains the original 2/0 ACSR conductor installed in 1930. Non-destructive testing was performed on the conductor in 2017 and revealed that it was in poor condition and showed that the conductor had less than 85% of its original rated breaking strength remaining. In addition, a routine inspection was performed on this line in 2015 that identified twelve (12) poles for replacement. A portion of this line was built using non-traditional transmission framing consisting of short wood poles with vertical post insulators mounted on cross arms, similar to distribution framing. The line is also absent an overhead ground wire (OHGW) which makes it vulnerable to lighting strikes that can cause momentary or sustained interruptions. The line has experienced a total of thirty-seven (37) interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, vegetation, pole and insulator failures. The most recent event occurred in April 2019 and was caused by a tree making contact with the line and breaking a crossarm.

In July of 2018, the transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. No new easement acquisition is required for the project. The transmission line design was provided to all departments involved for comment and review.

Approximately half of the conductor rebuild is within rolling hills and wooded terrain, while the remaining portion runs along rural and relatively sparse residential properties. Structures lie on both private and public land. Company owned easement and KYTC owned road right of way will be used to access the structures.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.

The structure design consists of fifty-two (52) steel single pole structures, sixty-nine (69) standard and custom steel H-frame structures, and eleven (11) custom steel self-supporting single pole dead end structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	29	721	5,874	7,280	13,904
2. Cost of Removal Proposed	-	1	328	1,664	1,993
3. Total Capital and Removal Proposed (1+2)	29	722	6,202	8,943	15,896
4. Capital Investment 2019 BP	33	200	5,046	6,713	11,992
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	33	200	5,046	6,713	11,992
7. Capital Investment variance to BP (4-1)	4	(521)	(828)	(566)	(1,912)
8. Cost of Removal variance to BP (5-2)	-	(1)	(328)	(1,664)	(1,993)
9. Total Capital and Removal variance to BP (6-3)	4	(522)	(1,156)	(2,230)	(3,904)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Funding for Distribution Operations is included in the proposed 2020 BP under project 155309.

Risks

- Without the proposed replacement of the existing conductor in the Farmers-Spencer Road 69kV line, the company risks increased exposure to line outages. The conductor along the 13.5 mile section has deteriorated over time and is beyond its expected useful life. There have been notable failures in the conductor's 80+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
- A single overhead transmission failure would impact over 900 customers, reducing their reliability until the repairs are complete.
- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
    - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
    - As the construction footprint continues to expand, this remains a risk for construction delays in 2020 and beyond.
    - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 17,010
   The recommendation is to replace 13.5 miles containing 2/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, two hundred twenty-three (223) wood structures will be replaced with one hundred thirty-two (132) new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 24,089
   The Next Best Alternative would be to construct a new 14.85 mile transmission line which would parallel 4.65 miles of existing line. Constructing a new route would require the purchase of 8.8 miles of new right of way and 4.7 miles of expanded right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Farmers-Spencer Road conductor replacement project for $15,896k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: 08/29/2019

Project Name: TEP-CR-Clay Village Tap-Shelbyville East

Total Capital Expenditures: $5,054k (Inlcuding $453k of contingency and $184k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - 145803
Distribution Operations - 159705

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

Conductor replacement of Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV. The line overloads during planning studies in the TEP process. This project is approved by the Company's Independent Transmission Organization (ITO).

During the TEP process, the Clay Village Tap to Selbyville East line overloads during the outage of East Frankfort – West Frankfort 138 kV line in the near term summer model.

This project will provide a facility rating increase for a 3.25 mile section of the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line. The existing summer normal and emergency rating is 41 MVA and a winter normal and emergency rating of 62 MVA. To eliminate the overload, the upgraded line will increase the rating to a summer rating of 83/105 MVA for the normal and emergency rating. The winter rating will be 128/141 MVA respectively.

Transmission plans to replace a 3.25 mile section of 2/0 7ST CU conductor between structure 177 and structure 240 on the Shelbyville to West Frankfort 69kV line with 556.5 ACSR 26/7, and the existing static wire between structure 177 and the East Shelbyville substation face of steel will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-three (53) existing wood structures will be replaced with new steel structures. In addition, this estimate assumes that eleven (11) existing steel structures installed during the 2017 priority pole replacement project will be reused. Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Transmission Lines	
May 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020	Steel Poles Received
January 2020	Line Construction Begins
July 2020	Line Construction Completed

Project Milestones – Distribution Operations	
June-August 2019	Engineering and Design
August 2019	Materials Ordered
October 2019	Materials Delivered
January 2020	Construction Start
July 2020	Construction Completed

This project was included in the 2019 Business Plan for $4,319k, with estimated spend of $100k in 2019 and $4,219k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined to include funding for vegetation clearing, structure access, and traffic control. The current total project cost is $5,054k. 2019 spend was approved by the Corporate RAC. The 2020 spend is included in the proposed 2020 BP.

	Transmission Lines	Distribution Operations	Total
Total 2019	$134k	$0k	$134k
Total 2020	$4,351k	$569k	$4,920k
Project Total	$4,485k	$569k	$5,054k
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line was identified in the TEP process and has also been reviewed and approved by [redacted] the Company's ITO.

The 3.25 mile section of 69kV line from Clay Village Tap to Shelbyville East will be reconductored. To eliminate the overload, the ratings will increase to a summer rating of 83/105 MVA for the normal and emergency rating. The winter rating will be 128/141 MVA respectively.

During the 50/50 summer peak season, a line outage of the East Frankfort to West Frankfort 138kV line results in an overload of 108.5% in the 2019 summer 50/50. This overload exists throughout the planning horizon. [redacted]

[redacted]

Structure replacement will consist of three (3) steel dead end structures, forty-three (43) tangent steel structures, seven (7) steel angle structures, and associated hardware and material.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	134	4,146	-	-	4,280
2. Cost of Removal Proposed		775	-	-	775
3. Total Capital and Removal Proposed (1+2)	134	4,920	-	-	5,054
4. Capital Investment 2019 BP	100	4,219	-	-	4,319
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	100	4,219	-	-	4,319
7. Capital Investment variance to BP (4-1)	(34)	73	-	-	39
8. Cost of Removal variance to BP (5-2)	-	(775)	-	-	(775)
9. Total Capital and Removal variance to BP (6-3)	(34)	(702)	-	-	(736)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Distribution funding was included in the 2019 BP under project 155309 for $569k and is included in the table above.

Risks

Without the recommended re-conductor of the Clay Village Tap-Shelbyville East section of the Shelbyville-West Frankfort 69kV line, there is risk of losing load in the Shelbyville area.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,920
   The recommendation is to replace 3.32 miles containing 336.4 ACSR 26/7 conductor with new 556.5 ACSR 26/7 conductor, existing static with OPGW, and fifty-three (53) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: Create Redundant Line NPVRR: ($000s) 8,857
   Create a redundant line in the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Clay Village Tap-Shelbyville East project for $5,054k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: September 25, 2019

Project Name: Bond-Virginia City Pole Replacement

Total Capital Expenditures: $2,132k (Including $194k of contingency and $67k of internal labor)

Total O&M: $0k

Project Number(s): LI-158885

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace sixteen (16) existing wood structures on the Bond-Virginia City 69kV line with steel. The scope of work includes the replacement of twelve (12) structures on the Bond-Virginia City 69kV line, and two (2) structures on the Toms Creek 69kV Tap identified through a 2018 inspection. The replacement of two (2) adjacent structures is required to accommodate the height of the new structures. This project will also support the installation of one (1) new two-way switch at the Toms Creek 69kV Tap Point. Due to the difficulty in obtaining an extended outage on the Toms Creek 69kV Tap, two (2) of the sixteen (16) structures will need to be replaced energized. The switch installation will be completed following the replacement of the energized structures. This will allow for the remaining fourteen (14) structures to be replaced de-energized.

Project Milestones	
July 2019	Engineering and Design
August 2019	Space reserved for steel pole production with manufacturer
October 2019	Steel Poles Ordered
October 2019	Steel Poles Received
January 2019	Line Construction Begins
May 2020	Line Construction Completed

This project was not included in the 2019 BP. This project is included in the proposed 2020 Business Plan (BP) for spend of $1,797k in 2020, using an average per structure cost prior to the completion of detailed engineering analysis to replace sixteen structures de-energized. Subsequent to the 2020 BP planning, a decision was made to include the switch installation to allow most of the poles to be replaced under a planned outage. In addition, incremental funding was required to support the energized work on the Toms Creek 69kV tap. The current total project cost is $2,132k, with spend of $116.5k in 2019 and $2,015.5k in 2020. 2019 spend was approved by the RAC. Incremental spend in 2020 will be funded through reallocation from other Transmission projects.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A PSC inspection was completed in 2018, and fourteen (14) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing eleven (11) steel H-Frame structures, two (2) steel three-pole running corners, two (2) steel single pole structures, one (1) steel two-way switch structure, and one (1) two-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	117	1,734	-	-	1,851
2. Cost of Removal Proposed	-	281	-	-	281
3. Total Capital and Removal Proposed (1+2)	117	2,016	-	-	2,132
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(117)	(1,734)	-	-	(1,851)
8. Cost of Removal variance to BP (5-2)	-	(281)	-	-	(281)
9. Total Capital and Removal variance to BP (6-3)	(117)	(2,016)	-	-	(2,132)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Bond-Virginia City 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,588
   The recommendation is to replace fourteen (14) wood structures with new steel structures during a scheduled outage. The remaining two structures will need to be replaced energized.

2. Alternative #1: NPVRR: ($000s) 3,700
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 3,031
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Bond-Virginia City pole replacement project for $2,132k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: Corydon-Rumsey Pole Replacement

Total Capital Expenditures: $8,030k (Including $730k of contingency and $208k of internal labor)

Total O&M: $0k

Project Number(s): LI-158880

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

<u>Brief Description of Project</u>

The proposed project is to replace two hundred (200) existing wood structures on the Corydon-Rumsey 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred ninety-six (196) structures identified through a 2018 inspection. The replacement of four (4) adjacent structures is required to accommodate the height of the new structures.

Eighty-one (81) structures will be replaced between the Rumsey Station and the Ashby Electric Tap. One hundred nineteen (119) structures will be replaced between the Ashby Electric Tap and the Corydon Station.

Project Milestones	
April 2019	Engineering and Design
June 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered to Inventory
January 2020	Steel Poles Charged from Inventory
January 2020	Line Construction Begins
April 2021	Line Construction Completed

This project was not included in the 2019 Business Plan (BP). Subsequent to the 2019 BP planning, a PSC required pole inspection was completed. The current total project cost is $8,030k, with estimated spend of $251k in 2019, $4,912k in 2020, and $2,867k in 2021. 2019 spend was approved by the Resource Allocations Committee. Spend in 2020 and 2021 is included in the proposed 2020 BP.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine pole inspection and Comprehensive Visual Inspection were completed in 2018, and one hundred ninety-six (196) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, four (4) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing one hundred eighty-seven (187) steel single pole structures, one (1) steel H-Frame structure, ten (10) single steel pole running corners, and two (2) steel three pole dead end structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next two years, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	245	4,273	2,464	-	6,982
2. Cost of Removal Proposed	6	639	403	-	1,048
3. Total Capital and Removal Proposed (1+2)	251	4,912	2,867	-	8,030
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(245)	(4,273)	(2,464)	-	(6,982)
8. Cost of Removal variance to BP (5-2)	(6)	(639)	(403)	-	(1,048)
9. Total Capital and Removal variance to BP (6-3)	(251)	(4,912)	(2,867)	-	(8,030)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP		-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Corydon-Rumsey 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 9,613
   The recommendation is to replace two hundred (200) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 14,911
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) $13,457
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Corydon-Rumsey Pole Replacement project for $8,030k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: Kentucky Dam-South Paducah Conductor Replacement

Total Capital Expenditures: $13,677k (Including $1,243k of contingency and $250k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: Phase I - LI-160438 & Phase II – LI-160439
Transmission Substations: 159504

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace two existing circuits in an 18.21 mile section of the South Paducah-Kentucky Dam 69kV line with a single circuit. This project will replace the existing overhead transmission line conductors that are over 90 years old and beyond their expected useful life. Performance of these circuits have diminished, with the most recent conductor failure occurring in 2018. Since 2012, these circuits rank as two of the worst performing transmission circuits for outage events. In addition, the existing 69kV (624) oil circuit breaker (OCB) at South Paducah will be retired and removed. Transmission Planning has completed a study of this circuit in coordination with [redacted] and confirmed that only one circuit is required between South Paducah and Kentucky Dam. A conversion to a single circuit eliminates the replacement for a significant number of the existing lattice towers. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to Ashland Oil, and the Princeton and Paducah areas.

Due to these modifications, [redacted] will be required to retire an existing 69kV interconnection tie line, along with the associated relays, protection, and communication path. In July of 2019, a payment was made to [redacted] in the amount of $50k to perform a facilities study to develop the scope, estimate, and schedule to complete these modifications.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the existing double circuit 18.21 mile section of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the South Paducah-Kentucky Dam section of the South Paducah-Kentucky Dam TVA-Kuttawa 69kV line in two phases. Phase one will consist of completing 76% of the proposed construction, and phase two will complete the remaining 24% of the proposed construction. The existing double circuit will be replaced with a single circuit of 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, seventeen (17) of the one-hundred eighteen (118) existing lattice steel towers will be replaced with new steel structures. Static peaks will be added to the remaining one-hundred one (101) lattice steel towers to accommodate the installation of new OPGW. Three (3) existing platform switch structures will be completely removed.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020-February 2020	Steel Poles Received
January 2020	Line Construction Begins
December 2021	Line Construction Completed

Transmission Substation will retire and remove the 69kV (624) OCB which will no longer be needed once the conductor is replaced and one of the circuits coming into the South Paducah Substation is eliminated.

Project Milestones – Transmission Substations	
January 2020-February 2020	Engineering and Design
November 2020	Construction Start
December 2020	Construction Completed

This project was included in the 2019 Business Plan (BP) under project 127111 for $7,991k. As the scope, timing and certainty of work has evolved, the estimates have been further refined. This project is included in the proposed 2020 Business Plan (BP) for $12,536k, including an estimated spend of $473k in 2019, $7,232.7k in 2020, $4,830.7k in 2021. Subsequent to the 2020 BP planning, an environmental study was completed, and it was determined that approximately 50% of the proposed construction would require matting to gain access to structures and limit property damages to these areas.

The current total project cost is $13,677k ($13,624k Transmission Lines, $53k Transmission Substations), with current estimates of $778k in 2019, $6,983k in 2020, and $5,916k in 2021. 2019 spend was approved by the Corporate Resource Allocation Committee. 2020 spend is included in the proposed 2020 BP. Incremental spend in 2021 will be addressed in the 2021 BP.

	Transmission Lines	Transmission Substations	Total
Total 2019	$778k	$0k	$778k
Total 2020	$6,930k	$53	$6,983k
Total 2021	$5,916k	$0k	$5,916k
Project Total	$13,624k	$53k	$13,677k
Contingency	10%	10%	

Why is the project needed? What if we do nothing?

The existing 18.21 mile double circuit section of 69kV line between the Kentucky Dam and South Paducah substations contains the original 3/0 ACSR conductor installed in the 1920s. Non-destructive testing was performed on the conductor in 2017 and revealed that it was in poor condition and showed that the conductor had less than 90% of its original rated breaking strength remaining. The circuits experienced a total of one hundred twenty-one (121) interruptions since 2012, ranking as two of the worst performing transmission circuits for outage events. The initiating events of these interruptions consist of lightning strikes, conductor failures, insulator failures, and several unknown events. The most recent event occurred in September of 2019 and no initiating cause was found. A PSC mandated ground patrol inspection was performed in 2017 and noted a significant number of flashed or broken insulators.

In August of 2018, the transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. In addition, easement information has been provided for the entire corridor. No new easement acquisition is required for the project. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of ten (10) steel H-frame structures, five (5) standard Z-Frame structures, one (1) steel three pole dead end structure, and one (1) steel single pole dead end structure. Of the seventeen structures being replaced, one structure (283A) is being replaced in order to separate the structure from the existing [redacted] tie line.

The Ashland Oil switch will be replaced as part of the Ashland Oil-City of Paducah existing switch replacement (ESR) project (157708). The ESR project will be completed in coordination with the proposed project.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	778	5,870	5,013	-	11,661
2. Cost of Removal Proposed	-	1,113	903	-	2,016
3. Total Capital and Removal Proposed (1+2)	778	6,983	5,916	-	13,677
4. Capital Investment 2019 BP	300	1,999	4,772	-	7,070
5. Cost of Removal 2019 BP	-	-	920	-	920
6. Total Capital and Removal 2019 BP (4+5)	300	1,999	5,692	-	7,991
7. Capital Investment variance to BP (4-1)	(478)	(3,871)	(241)	-	(4,591)
8. Cost of Removal variance to BP (5-2)	-	(1,113)	17	-	(1,096)
9. Total Capital and Removal variance to BP (6-3)	(478)	(4,984)	(224)	-	(5,686)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2019 BP under project 127111.

Risks

- Without the proposed replacement of the existing conductor in the Kentucky Dam-South Paducah 69kV line, the company risks increased exposure to line outages. The conductor along the 18.21 mile section has deteriorated over time and is beyond its expected useful life. There have been notable failures in the conductor's 90+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
- A single overhead transmission failure would impact customers, reducing their reliability until the repairs are complete.
- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
  - As the construction footprint continues to expand, a risk remains for construction delays in 2020 and beyond.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 16,310
   Transmission Lines will replace 18.21 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, seventeen (17) existing lattice steel towers will be replaced with new steel structures, and static peaks added to the remaining one-hundred one (101) lattice steel towers. In addition, Transmission Substations will retire and remove the existing 69kV (624) OCB at South Paducah.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: Rebuild the Line NPVRR: ($000s) 22,517
   The Next Best Alternative would be to rebuild the 18.21 mile transmission line between the Kentucky Dam and South Paducah substations. Rebuilding the line would add significant cost. Locating areas outside of the existing easement to stage the additional structures would be challenging. In addition, constructing a new line would create additional disturbance in an already difficult work location.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Kentucky Dam-South Paducah Conductor Replacement project for $13,677k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: Nebo-Wheatcroft Pole Replacement

Total Capital Expenditures: $4,415k (Including $401k of contingency and $132k of internal labor)

Total O&M: $0k

Project Number(s): 157635

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred (100) existing wood structures on the Nebo-Wheatcroft 69kV line with steel during a scheduled outage. The scope of work includes the replacement of ninety-seven (97) structures identified through a 2018 inspection. The replacement of three (3) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
July 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
December 2019-January 2020	Steel Poles Received
March 2019	Line Construction Begins
June 2020	Line Construction Completed

This project was included in the 2019 Business Plan.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and ninety-seven (97) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing seventy-two (72) steel single pole structures, sixteen (16) steel H-Frame structures, eleven (11) single steel pole running corners, and one (1) single steel pole dead-end structure.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	353	3,827	-	-	4,180
2. Cost of Removal Proposed	-	235	-	-	235
3. Total Capital and Removal Proposed (1+2)	353	4,063	-	-	4,415
4. Capital Investment 2019 BP	798	4,175	-	-	4,972
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	798	4,175	-	-	4,972
7. Capital Investment variance to BP (4-1)	445	348	-	-	793
8. Cost of Removal variance to BP (5-2)	-	(235)	-	-	(235)
9. Total Capital and Removal variance to BP (6-3)	445	112	-	-	557

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Nebo-Wheatcroft 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,372
   The recommendation is to replace one hundred (100) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 7,664
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 5,663
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Nebo-Wheatcroft Pole Replacement project for $4,415k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment and Contract Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: [redacted] Interconnection Green River-Green River Steel
Contract Name (Good/Service): Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company

[redacted]

Contract Authorization Requested: $2,750k (Including $217k of contingency)

Contract Term: N/A

Total Capital Expenditures Requested: $2,750k (Including $217k of contingency and $152k of internal labor)
Total O&M: $0k

Project Number(s): 158817 (Substations), 158818 (Lines) and 160252 (Easement)
Business Unit/Line of Business: Transmission

Prepared/Presented By: Adam Smith

<u>Brief Contract/Project Description</u>
An Interconnect Agreement (IA) with [redacted] has been approved for [redacted] to connect a new 138kV line to the Green River to Green River Steel line, which will become a three terminal line between KU's Green River and Green River Steel substations and [redacted] substation.

This project was approved for a total of $552k during May 2019 which included full authorization of $334k for transmission substation project (158817) and $218k for preliminary engineering on transmission lines project (158818). Separately, easement acquisition was approved for $120k on project 160252 during May 2019. In addition, a revision was submitted for intermediate approval of spending through mid November of 2019 in Octobor of 2019 in the amount of $1,335k, ($224k Subs, $991k Lines construction, and $120k Lines easement acquisition). This intermediate approval was needed to ensure the project could remain on schedule to meet [redacted] desired in-service date of May 2020 without exceeding the authorized spending level.

Per Facility Study Schedule 4 in the IA, the original estimated cost of this work was $1,593k. Once detailed engineering analysis was completed and contractor pricing obtained, the estimates were further refined. The current total project estimate is $2,750k ($224k Transmission Substations, $2,406k Transmission Lines Construction, $120k Transmission Lines Easement acquisition). This project was not included in the 2019 Business Plan. This project is included in the proposed 2020 BP for $2,234k. [redacted] will reimburse LG&E/KU for 100% of the costs to complete construction of this project per the agreement dated November 13, 2018. [redacted] has been informed of the increased anticipated project costs and [redacted] has confirmed in writing acknowledgement and acceptance of the updated costs.

	Transmission Substation	Transmission Lines Construction	Transmission Lines Easement Acquisition	Total
Total 2019	$174k	$1,537k	$120k	$1,831k
Total 2020	$50k	$869k	$0k	$919k
Project Total	$224k	$2,406k	$120k	$2,570k
Contingency	0%	10%	0%	

Transmission Substations will install (1) 009-794 Retrofit Line Relay Panel and (1) 100-714 Retrofit Line Relay Panel (both w/ SEL-411L and SEL-421 relay packages) and will remove electromechanical relays on both the 009-794 and 100-714.

Project Milestones – Transmission Substations	
August 2019	Engineering and Design
August 2019	Materials Ordered
October 2019	Materials Received
October 2019	Construction Start
January 2020	Construction Completed

Transmission Lines will install 0.97 miles of new 954 ACSR 45/7 conductor beginning at the tap point on the Green River-Green River Steel 138kv line and extending to the [redacted] 138kV Substation. Also included in the scope of this project is the installation of eight (8) new steel structures and the removal of four (4) existing structures. A 3-way switch will be installed at the new [redacted] tap-point. Approximately one acre of new right of way easement has been acquired at the tap point.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
May 2019	Space reserved for steel pole production with manufacturer
July 2019	Steel Poles Ordered
September 2019	Steel Poles Received
October 2019	Line Construction Begins
May 2020	Line Construction Completed

In addition to the work described above, [redacted] will install new fiber optic cable between the KU Green River Steel station and the [redacted] station. LG&E/KU will assume ownership of the fiber as part of the LG&E/KU Green River Steel to [redacted] 138 and 69 kV Line Differential Protection Scheme.

Why is the project needed? What if we do nothing?

[redacted] is retiring both generating units at the Elmer Smith station. Unit 1 was retired in June of 2019. Unit 2 will be retired in June of 2020. [redacted] will replace this generation by importing power from [redacted] This interconnection is required to maintain reliability to the transmission system.

LG&E/KU is obligated to provide transmission and generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. This project will have minimal impact of reliability and/or the customer experience.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
OMU Payments	$521k	$2,012k	$0k	$0k	$0k	$0k	$2,533k
Contingency	$0k	$217k	$0k	$0k	$0k	$0k	$217k
Total Payments	$521k	$2,229k	$0k	$0k	$0k	$0k	$2,750k

This project was not included in the 2019 Business Plan. This project is included in the proposed 2020 BP for $2,234k, including $890k in 2019 and $1,344k in 2020, less reimbursements for a net $6k.

The current total project cost of $2,750 exceeds the amount included in the 2020 BP on a gross basis, however [redacted] will reimburse LG&E/KU for 100% of the costs of construction to complete this project per the agreement dated November 13, 2018. [redacted] has been informed of the increased anticipated project costs and [redacted] has confirmed in writing acknowledgement and acceptance of the updated costs.

The Transmission Lines project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,823	694	-	-	2,517
2. Cost of Removal Proposed	8	225	-	-	233
3. Total Capital and Removal Proposed (1+2)	1,831	919	-	-	2,750
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(1,823)	(694)	-	-	(2,517)
8. Cost of Removal variance to BP (5-2)	(8)	(225)	-	-	(233)
9. Total Capital and Removal variance to BP (6-3)	(1,831)	(919)	-	-	(2,750)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Failure to perform risk and mitigation measures.
- Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,512

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted], has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.

3. Alternative #2: Construct a Ring Bus NPVRR: ($000s) 7,644
   Construct a 138kV three breaker ring bus at the proposed transmission tap point in the Green River – Green River Steel 138 KV line and install 1.04 miles of new 954 ACSR 45/7 conductor beginning at the tap point on the Green River-Green River Steel 138kv line and extending to the [redacted] 138kV Substation. Included in the scope of this project is the installation of eight (8) new steel structures and the removal of four (4) existing structures.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] Interconnection Green River-Green River Steel project for $2,750k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company contract for $2,750k with [redacted].

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations David Cosby	
Director		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: TEP Rogers Gap Distribution Station

Total Capital Expenditures: $7,174k (Including $648k of contingency and $514k of internal labor)

Project Number(s): Transmission Lines – LI-159700
Distribution Substations – 160207
Distribution Operations - 160773

Business Unit/Line of Business: Transmission and Distribution

Prepared/Presented By: Dan Hawk/Delyn Kilpack

Brief Description of Project

This Investment Proposal (IP) requests funding authority for distribution substation, distribution circuit, and transmission line improvements in and around the KU Rogers Gap Substation near Georgetown, KY. The goal of this project is to reduce the loading on the 69kV transmission system in the area in order to mitigate a contingency related conductor overload risk. The Adams – Delaplain 69kV tap overloads during planning studies and was identified through the Transmission Expansion Plan (TEP) process.

This project was originally identified under the TEP-CR-Adams-Delaplain Tap conductor replacement project (144065). After preliminary engineering was underway, it was determined that moving the load at Rogers Gap from 69kV to 138kV is a lower cost alternative.

In the 90/10 winter peak conditions and during an outage of Scott County to Rogers Gap causes the Adams – Delaplain 69 kV to load to 101.9% in 2019. In the 50/50 winter peak, the overload is 101.5% in 2025.

The Adams-Delaplain conductor replacement project was approved by [redacted] the Company's Independent Transmission Organization (ITO). [redacted] has been supplied documentation showing that the Rogers Gap Distribution Substation project is the lower cost alternative of both projects and is expected to support the alternative solution.

A Network Integration Transmission Service (NITS) request will be submitted to [redacted] in October of 2019 to get approval for modifications to the transmission system.

Project Scope and Milestones

Transmission Lines will install four (4) steel self-supporting dead-end structures, one (1) steel self-supporting tangent structure, and associated hardware and material as needed to terminate and connect the 138kV transmission line to the new 138kV substation.

Project Milestones – Transmission Lines	
April 2019-September 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
April 2020	Steel Poles Received
August 2021	Line Construction Begins
October 2021	Line Construction Completed

Distribution Substation will provide the installation of a new 15/28 MVA 138-12 kV transformer, steel transmission/distribution bay, one (1) 138kV transformer breaker, two (2) 138kV motor operated switches, one (1) 12kV switchgear, control house, underground cable, conduit, manholes, SPCC, and other associated equipment in the Rogers Gap substation.

Project Milestones – Distribution Substations	
November 2019-April 2020	Engineering and Design
December 2019	Materials Ordered
December 2020	Materials Delivered
February 2021	Construction Start
October 2021	Construction Completed

Distribution Operations will provide the installation of manholes, underground cable, poles, overhead conductor, and switches as needed to connect the new 12kV substation switchgear to the existing distribution circuits. In addition, Distribution Operations will relocate one distribution pole currently in the Transmission right of way in order to maintain proper mid-span clearances and transfer existing distribution conductor to the new transmission structures as needed. An air break switch will be installed between the existing distribution circuits to help facilitate construction.

Project Milestones – Distribution Operations	
September 2020-October 2020	Engineering and Design
November 2020	Materials Ordered
February 2021	Materials Delivered
March 2021	Construction Start
September 2021	Construction Completed

Although it will not serve any normal service load, it is proposed that the existing 22.4 MVA, 69-12 kV transformer, steel, breakers, and other associated equipment remain in the Rogers Gap Substation in order to support the Company's Distribution Substation Transformer Contingency Program (N1DT).

This project was included in the 2019 BP for $3,762k under project 144065 (Adams-Delaplain Conductor Replacement) with estimated spend of $156k in 2018, and $3,606k in 2019. Once detailed engineering was completed, the estimates for this project were further refined, and the estimate was revised to include incremental funding of $3,671k, bringing the total project cost to $7,433k. Upon further analysis, it was determined that moving the load at Rogers Gap is the lower cost and preferable alternative to minimize customer risk. The TEP Rogers Gap

Distribution Station project is included in the proposed 2020 BP for $7,688k with estimated spend of $1,047k in 2020, $6,641k in 2021. The current total project cost is $7,174k with estimated spend of $3,264k in 2020 and $3,910k in 2021. Incremental spend in 2020 will be funded through reallocation from other Transmission projects.

	Transmission Lines	Distribution Substation	Distribution Operations	Total
Total 2020	$297k	$2,830k	$137k	$3,264k
Total 2021	$1,801k	$1,971k	$138k	$3,910k
Project Total	$2,098k	$4,801k	$275k	$7,174k
Contingency	10%	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>
Transmission Planning has identified a transmission system need in the Georgetown area and has a project included in the Transmission Expansion Plan (TEP) for transmission conductor upgrades to mitigate conductor overloads during contingency conditions. Under the original project (Adams-Delaplain Conductor Replacement) it was proposed to replace 2.86 miles of 266 ACSR with 795 ACSR conductor in the Adams-Delaplain Tap section of the Adams-Oxford 69kV transmission line. However, Transmission Planning, in conjunction with Distribution System Planning, has now identified an alternate project (Rogers Gap Distribution Station) that transfers the Rogers Gap substation load from the 69kV to the 138kV transmission system and accomplishes the same goals as the original project.

The Do Nothing option is not considered to be an acceptable option because it is not compliant with transmission planning guidelines.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	-	-	3,256	3,611	6,868
2. Cost of Removal Proposed	-	-	8	299	306
3. Total Capital and Removal Proposed (1+2)	-	-	3,264	3,910	7,174
4. Capital Investment 2019 BP	156	3,606	-	-	3,762
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	156	3,606	-	-	3,762
7. Capital Investment variance to BP (4-1)	156	3,606	(3,256)	(3,611)	(3,105)
8. Cost of Removal variance to BP (5-2)	-	-	(8)	(299)	(306)
9. Total Capital and Removal variance to BP (6-3)	156	3,606	(3,264)	(3,910)	(3,412)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2019 BP under project 144065. The 2019 BP estimate was based on replacing the conductor, using the existing double circuit structures.

Risks

- The estimated costs of the distribution substation, distribution circuits, and transmission lines are considered high level estimates at this time because the projects have not been formally designed. The costs are based on completed work for other projects of similar scope and size.
- Failure to advance and complete this project in a timely fashion could expose the Company to periods of noncompliance with federally mandated transmission planning standards.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 9,001
   The recommended option proposes the installation of a 28 MVA 138-12kV transformer along with other associated substation, distribution, and transmission equipment in and near the Rogers Gap substation in order to change the transmission delivery voltage from 69kV to 138kV

2. Alternative #1: Do Nothing NPVRR: N/A
   As previously discussed, the “do nothing” option is not considered a valid option because it violates the Company’s Transmission Planning Guidelines. .

3. Alternative #2: Replace Conductor NPVRR: ($000s) 9,583
   This previously described option considers the replacement of 2.86 miles of 266 ACSR with 795 ACSR conductor in the Adams-Delaplain Tap section of the Adams-Oxford 69kV transmission line. The estimated capital cost of this option is $7,433k. In addition, this option puts [redacted] on a radial feed for approximately 10 weeks which is a risk in serving [redacted] load.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Rogers Gap Distribution Station project for $7,174k to alleviate contingency related transmission conductor overloads on the Adams-Oxford 69kV transmission line and comply with federally mandated standards.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: TEP-CR-Ford-Freys Hill

Total Capital Expenditures: $5,159k (Including $494k of contingency and $351k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines – LI-000088
Distribution Operations - 159259

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Ford – Freys Hill Tap 69kV line overloads during planning studies in the Transmission Expansion Plan (TEP) process with a need date of 2019. Subsequent TEP's have confirmed the need for this project. This project was approved by [redacted] the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak conditions, an outage of the Middletown – Lyndon 69kV line or the Lyndon to Freys Hill 69kV line causes the Ford – Freys Hill Tap 69kV line to overload 100.1% in 2019. The overload is 103.4% in 2027. During the 50/50 summer peak conditions, the overload is 101.5% in 2029.

When the project is completed the summer emergency rating will go from 100 MVA to 132 MVA.

This project was opened for preliminary services in October of 2019 to begin vegetation clearing to gain access to the right of way for surveying and line construction.

Transmission Lines plans to replace 1.7 miles of existing 795 All Aluminum Conductor (ACC) between structure 18 at the Worthington Tap Point to structure 54-1 outside of the Ford substation on the Ford-Freys Hill 69kV line with 954 Aluminum Conductor Steel Reinforced (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, forty-one (41) existing wood structures will be replaced with new steel structures. Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Transmission Lines	
March-July 2019	Engineering and Design
August 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
February 2020	Steel Poles Received
February 2020	Line Construction Begins
June 2020	Line Construction Completed

Project Milestones – Distribution Operations	
November-December 2019	Engineering and Design
April 2020	Materials Ordered
May 2020	Materials Delivered
May 2020	Construction Start
December 2020	Construction Completed

This project was included in the 2019 Business Plan for $2,133k, with estimated spend of $50k in 2019 and $2,083k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined. This project was included in the 2020 BP for $4,535k, with estimated spend of $284k in 2019 and $4,251k in 2020. Subsequent to the 2020 BP, funding was included for self-supporting structurs, vegetation clearing, and the transferring of distribution underbuild. The current total project cost is $5,159k, with estimated spend of $382k in 2019 and $4,777k in 2020. 2019 spend was approved by the Corporate RAC. Incremental spend in 2020 will be funded by a reduction in other transmission and distribution capital projects.

	Transmission Lines	Distribution Operations	Total
Total 2019	$382k	$0k	$382k
Total 2020	$4,439k	$338k	$4,777k
Project Total	$4,821k	$338k	$5,159k
Contingency	10%	20%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Ford – Freys Hill Tap 69kV line was identified in the TEP and approved by [redacted] the Company's Independent Transmission Organization (ITO).

The Ford – Freys Hill Tap 69kV line currently consists of 0.69 miles of 795 MCM 61X AAC conductor (verified at 176/176°F). To eliminate the overload, this line section will be replaced with 954 ACSR conductor.

During the 90/10 winter peak conditions, an outage on either the Lyndon to Middletown 69kV line or the Lyndon to Freys Hill 69kV line results in an overload of 100.1% in the 2019 summer and increases to 103.4% in 2027 summer. This overload exists throughout the planning horizon.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

[redacted]

Structure replacement will consist of thirty-three (33) single pole structures, three (3) self-supporting steel angle structures, and five (5) self-supporting steel dead end structures. Four span guys and stub poles crossing over [redacted] will be eliminated.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	382	4,265	-	-	4,647
2. Cost of Removal Proposed	-	512	-	-	512
3. Total Capital and Removal Proposed (1+2)	382	4,777	-	-	5,159
4. Capital Investment 2019 BP	50	2,083	-	-	2,133
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	50	2,083	-	-	2,133
7. Capital Investment variance to BP (4-1)	(332)	(2,182)	-	-	(2,513)
8. Cost of Removal variance to BP (5-2)	-	(512)	-	-	(512)
9. Total Capital and Removal variance to BP (6-3)	(332)	(2,694)	-	-	(3,026)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Without the recommended re-conductor of the Ford – Freys Hill Tap 69kV line, there is risk of losing load at Ford, Freys Hill, Lyndon and Worthington.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 6,264
   The recommendation is to replace 1.7 miles containing 795 AA conductor with new 954 ACSR conductor, existing static with OPGW, and thirty-eight (38) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts the customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Build Redundant Line NPVRR: ($000s) 15,938
   This alternative requires building a second 69kV line from Lyndon – Freys Hill and construct a four breaker 69kV ring bus at Lyndon.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TEP-CR-Ford-Freys Hill project for $5,159k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: TEP-CR-Mid Valley-Finchville

Total Capital Expenditures: $6,882k (Including $626k of contingency and $136k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - LI-159243

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack/Chris Balmer

Brief Description of Project

The Mid Valley Simpsonville - Finchville 69kV line overloads during planning studies. This overload was first identified in the 2019 Transmission Expansion Plan (TEP).

During the 90/10 and 50/50 winter peak conditions, an outage of the Blue Lick 345/161kV transformer results in an overload of the Mid-Valley Simpsonville to Finchville 69 kV line. The 90/10 winter peak overload is 113.8% in 2020. The 50/50 winter peak is 111% in 2020 and the summer peak is 101.3%.

This project will provide a facility rating increase for the 5.13 miles of the Mid Valley Simpsonville - Finchville 69kV line. To eliminate the overload, the upgraded line will increase the rating to a summer rating of 94/119 MVA for the normal and emergency rating. The winter rating will be 144/159 MVA respectively for normal and emergency rating.

Transmission plans to replace a 5.13-mile section of 397 ACSR 26/7 conductor between structure 273A and structure 307 on the Mid Valley-Finchville section of the Mid Valley-Simpsonville 733 69kV Tap with 795 ACSR 26/7, and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, thirty-five (35) existing steel towers, and two (2) existing steel single pole structures will be replaced with thirty-six (36) new steel structures.

Project Milestones – Transmission Lines	
May 2019	Engineering and Design
November 2019	Space reserved for steel pole production with manufacturer
January 2020	Steel Poles Ordered
March 2020	Steel Poles Received
March 2020	Line Construction Begins
November 2020	Line Construction Completed

This project was included in the proposed 2020 Business Plan for $5,946k, with estimated spend of $262k in 2019 and $5,684k in 2020. As scope, timing, and certainty of work has evolved, outage constraints identified during the summer months will now require this project to be completed under a spring and fall outage. The current total project cost is $6,882k, with estimated spend of $564k in 2019 and $6,318k in 2020. 2019 spend was approved through the Corporate Resource Allocation Committee. Incremental spend in 2020 will be funded through a reduction in other Transmission capital projects. This project was not included in the 2019 BP.

<u>Why is the project needed? What if we do nothing?</u>

The overload of Mid Valley Simpsonville - Finchville 69kV line was identified in the TEP process and has also been reviewed and approved by [redacted] the Company's Independent Transmission Organization (ITO).

The 5.13-mile, 69 kV line from Mid Valley Simpsonville - Finchville will be reconductored. To eliminate the overload, the ratings will increase to a summer rating of 94/119 MVA for the normal and emergency rating. The winter rating will be 144/159 MVA respectively.

During the 90/10 and 50/50 winter peak conditions, an outage of the Blue Lick 345/161kV transformer results in an overload of the Mid-Valley Simpsonville to Finchville 69 kV line. The 90/10 winter peak overload is 113.8 in 2020. The 50/50 winter peak is 111% in 2020 and the summer peak is 101.3%. This overload exists throughout the planning horizon. [redacted]

Structure replacements will consist of thirty (30) steel H-Frame structures, one (1) custom steel switch structure, and five (5) steel single pole dead-end structures.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	564	5,341	-	-	5,905
2. Cost of Removal Proposed	-	977	-	-	977
3. Total Capital and Removal Proposed (1+2)	564	6,318	-	-	6,882
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(564)	(5,341)	-	-	(5,905)
8. Cost of Removal variance to BP (5-2)	-	(977)	-	-	(977)
9. Total Capital and Removal variance to BP (6-3)	(564)	(6,318)	-	-	(6,882)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Without the recommended re-conductor of the Mid Valley-Finchville section of the Mid Valley-Simpsonville 733 69kV Tap, there is risk of violating the Company's Planning Guidelines.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 8,374
   The recommendation is to replace 5.13 miles containing 397 ACSR 26/7 conductor with new 795 ACSR 26/7 conductor, existing static with OPGW, and thirty-seven (37) existing structures will be replaced with thirty-six (36) new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: Construct Redundant Line NPVRR: ($000s) 18,118
   Create a redundant Blue Lick 345/161kV transformer. Construct additional 161kV rung to the west includes 161kV GCB, Switch & Surge Arrestors. Construct 2nd 345/161kV, 420MVA transformer with dedicated 345kV GCB, Switch. Add dedicated 345kV GCB on HV side of existing 345/161kV transformer. Add two 345kV GCB's with dedicated isolation switches. Construct 345kV rung to MT line exit to retain 345kV source under 345/161kV HV GCB breaker failure scenario.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Mid Valley-Finchville project for $6,882k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: TEP Hardin County

Total Capital Expenditures: $27,512k (Including $2,648k of contingency and $909k of internal labor)

Total O&M: $0k

Project Number(s): 144070,157806,LI-000100,LI-000102,LI-161041,SU-000203,SU-000439,161065

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of the Project

The Hardin County projects include installation and/or construction of a 2nd Hardin County 345/138 kV transformer, 2nd Hardin County 138/69 kV transformer, and a 2nd Hardin County - Elizabethtown 69 kV line. Other ancillary projects were identified and are listed below. The projects were identified in the Transmission Expansion Plan (TEP) process and are approved by the company's Independent Transmission Organization (ITO). There are significant low voltage violations when studying the outage of the existing Hardin County 345/138 kV transformer. Therefore, these projects are required to meet the requirements of NERC Reliability Standard TPL-001-4 and the Company's Planning Guidelines. Additional work is required at Elizabethtown 69 kV to reconfigure the bus and add a bus tie breaker. This is vital to maintenance efforts, and greatly increases customer reliability. Preliminary engineering has already begun with an expected completion date in 2022. Transmission Planning evaluated these projects to ensure they are adequate throughout the ten-year planning horizon under varying load forecasts.

Joint studies between LG&E/KU and [redacted] were performed in 2017 and 2018 resulting in the following list of projects for LG&E/KU. [redacted] has its own list of related projects.

- 2nd 345/138 kV transformer at Hardin County - SU-000203/157806
- 2nd 138/69 kV transformer at Hardin County - SU-000203
- Split the 69 kV straight bus at Hardin County into two buses with a bus tie breaker - SU-000203
- 2nd 69 kV line from Hardin County to Elizabethtown - LI-000102/SU-000439/157806
- MOT increase of the Elizabethtown – Nelson County 138 kV line - LI-000100
- MOT increase of Elizabethtown – Elizabethtown #2 69 kV line - 144070
- Elizabethtown 69 kV Bus Tie Breaker - SU-000439/157806

Without the Hardin County expansion project, severe low voltage violations are likely under peak load conditions following the loss of the Hardin County 345/138 kV transformer. [redacted]

[redacted]

[redacted]

Table 1 shows the number of voltage criteria vioaltions identifed in the LG&E/KU and EKPC joint study.

[redacted]

Table 2 shows the number of potentially affected customers.

[redacted]

The solution identified is adding a 2nd 345/138 kV transformer. When adding the 2nd 345/138 kV transformer, flows are significantly increased in the 138 kV and 69 kV systems. Therefore, a 2nd 138/69 kV transformer and 2nd 69 kV line are also required.

The risk associated with the identified violations is increased when considering the Hardin County area has positive load growth, compared to other areas of the LG&E or KU systems. Electric Distribution Operations has seen significant growth along Black Branch Road in Hardin County due to expansions from large industrial customers in the area, and significant commercial growth along US Highway 31W. Additionally, KU has seen expansion activities at nearly all distilleries in the area. In response to this growth, KU Distribution has constructed two new substations (Rineyville and Black Branch) and currently has projects under construction to increase capacity at the Barton substation.

[redacted].

[redacted]

[redacted]

[redacted]

The existing and new substation layouts at Hardin County, based on the proposed projects, are shown in Figures 6 and 7 below.

CONFIDENTIAL INFORMATION REDACTED

[redacted]

[redacted]

During project engineering, it was determined that the Elizabethtown 69 kV bus required a bus tie breaker to allow bus outages for maintenance. This includes additional line reconfiguration to best utilize the bus tie. [redacted]

[redacted]

[redacted].

[redacted]

Adding a 69 kV bus tie breaker requires enlarging the substation, adding two new bays and re-terminaing several LG&E and EKPC lines. In total, the addition of the bus tie breaker adds $4,310k to the cost of the project.

<u>Project Scope and Milestones</u>

This project will install a 2nd 345/138 kV and 2nd 138/69 kV transformer at Hardin County, build a new 1.3 mile 69 kV line from Hardin County to Elizabethtown, add a 69kV bus tie breaker at Hardin and split the bus, add a 69kV bus tie breaker at Etown and split the bus, increase the maximum operating temperature (MOT) of the Nelson County to Elizabethtown 138 kV line (15.5 miles), increase the MOT of the Elizabethtown to Elizabethtown #2 Tap 69 kV line section (2.24 miles), and relocate approximately 0.6 miles of various lines around the Elizabethtown and Hardin County substations.

	144070 TEP MOT ETOWN ETOWN 2	157806 TEP Hardin Co Line Work	LI-000100 TEP MOT Etown Nelson Co	LI-000102 TEP NL Hardin Co Etown New 2nd	LI-161041 TEP-NL-Hardin Co-Etown ROW	SU-000203 TEP Hardin Co Etwn 69kV 2 Line	SU-000439 TEP Etown Bay Add	161065 Sale of LG&E Trans-former to KU
Materials	2020	2021	2021	2020	2020	2020	2020	2020
Construction	2020-2021	2022	2021	2021	-	2020-2022	2020-2022	-

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,181	7,262	14,929	3,608	26,980
2. Cost of Removal Proposed	2	132	106	292	532
3. Total Capital and Removal Proposed (1+2)	1,183	7,394	15,035	3,900	27,512
4. Capital Investment 2019 BP	1,050	3,144	11,012	1,999	17,205
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,050	3,144	11,012	1,999	17,205
7. Capital Investment variance to BP (4-1)	(131)	(4,118)	(3,917)	(1,609)	(9,775)
8. Cost of Removal variance to BP (5-2)	(2)	(132)	(106)	(292)	(532)
9. Total Capital and Removal variance to BP (6-3)	(133)	(4,250)	(4,023)	(1,901)	(10,307)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project will utilize a spare transformer that is currently located at Blue Lick. The net book value of the spare transformer is included in project SU-000203 and the offsetting credit for the same from LG&E to KU is netted with that cost below.

The 2019 BP totals above also include SU-000196 which was budgeted as part of this group of projects but which was later replaced by the other estimates. This project is also included in the 2020 BP for a total of $22,554k with $540k in 2019, $4,600k in 2020, $17,361k in 2021 and $53k in 2022. The shortfall in 2020 will be covered in the RAC Approved 0+12 forecast and the 2021 and 2022 spending will be included in the 2021 BP. The primary reasons for the cost increase above the 2019 and 2020 BPs is due to adding scope at Elizabethtown which includes installing a new control house, adding a bus tie breaker and splitting the bus.

($000s)	144070 TEP MOT ETOWN ETOWN 2	157806 TEP Hardin Co Line Work	LI-000100 TEP MOT Etown Nelson Co	LI-000102 TEP NL Hardin Co Etown New 2nd	LI-161041 TEP-NL-Hardin Co-Etown ROW	SU-000203 TEP Hardin Co Etwn 69kV 2 Line	SU-000439 TEP Etown Bay Add	161065 Sale of LG&E Trans-former to KU	Total
Company Labor	31	77	4	102	-	422	273	-	909
Contract Labor	539	907	57	1,355	40	4,572	2,325	-	9,795
Materials	194	463	53	550	-	7,584	1,810	(1,001)	9,653
Other	-	-	-	0	100	0	0	-	101
Contingency	90	191	16	263	16	1,538	534	-	2,648
Burdens	140	293	28	386	16	2,889	967	(313)	4,406
Gross Capital Expenditure	994	1,931	158	2,656	172	17,005	5,909	(1,314)	27,512
Reimbursement	-	-	-	-		-	-	-	-
Net Capital Expenditure	994	1,932	158	2,656	172	17,005	5,909	(1,314)	27,512
Contingency %	10%	11%	11%	11%	10%	10%	10%	0%	10%

Risks

There is a risk of not getting the outages required to do the construction. Discussions with [redacted] are ongoing and [redacted] has agreed to upgrade one of their 69 kV lines in order to accommodate identified outages. Preliminary engineering is required in order to develop an outage schedule to best mitigate this risk.

A Storm Water Pollution Prevention Plan (SWPPP) will be needed for grading and enlarging the Hardin County substation. In addition, a "Waters of the US" permit may be needed from the Kentucky Division of Water and the US Army Corps of Engineers.

There is risk of a compliance violation of NERC TPL-001-4 if the projects are not built. Also, LG&E/KU and EKPC loads in the Hardin County area would be left at risk. See Figure 1 for the area loads at risk.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 29,564

2. Alternative #1: NPVRR: ($000s) 33,300
   Several alternatives were considered during the TEP process. The 2nd lowest cost alternative is to install a 2nd 345/138 transformer at Hardin County, but instead of adding a 2nd 138/69 transformer, build a new 1.3 mile 138 kV line from Hardin County to Elizabethtown, replace the existing 138/69 transformer at Elizabethtown with a 138/69 185MVA transformer, add a four breaker 138kV ring bus at Hardin, reconfigure the 69kV bus at Hardin, increase the maximum operating temperature (MOT) of the Nelson County to Elizabethtown 138 kV line (15.5 miles), increase the MOT of the Elizabethtown to Elizabethtown #2 Tap section (2.24 miles), and relocating approximately 0.6 miles of various lines around the Elizabethtown and Hardin County substations. This alternative includes splitting the Elizabethtown 69 kV bus with a bus tie breaker for maintenance.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk, violates NERC TPL-001-4 and violates the company's Planning Guidelines.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Hardin County project for $27,512k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Bond-Dorchester Pole Replacement

Total Capital Expenditures: $4,581k (Including $416k of contingency and $139k of internal labor)

Total O&M: $0k

Project Number(s): 157638

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Kelly Mefford/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-seven (37) existing wood structures with new steel structures on the Bond-Dorchester 69kV line during a scheduled outage. The scope of work includes the replacement of thirty-six (36) structures identified through inspection. One (1) existing switch structure will be relocated to the Clinch Valley Tap point, and the existing switch will be replaced with one (1) new 2-way switch. In addition, one (1) additional existing wood switch structure will be replaced with a new steel structure to support the installation of one (1) new one-way switch for an emergency tie to the St Paul-Dorchester 69kV line.

Project Milestones	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020	Steel Poles Received
October 2020	Line Construction Begins
April 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $2,453k for work to be completed in 2020, using an average per structure cost prior to the completion of detailed engineering analysis. This project is included in the proposed 2020 BP for $5,724k, with estimated spend of $592k in 2019, $2,493k in 2020, and $2,639k in 2021. The estimate used for the 2020BP was based on historical unit costs typical for the structure type and region of the service territory. As detailed engineering was complete, the scope and project plan was further refined and the estimate was updated based on this additional detail. The current total project cost is $4,581k, with spend of $2,200k in 2020, and $2,381k in 2021.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2017, and a comprehensive visual inspection was completed in 2018. From these inspections, thirty-six (36) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, one existing switch will be replaced with a new 2-way switch. This project also includes the replacement of (1) existing wood switch structure with a new steel structure, and the installation of one (1) new one-way switch.

The scope of work consists of installing twenty-four (24) steel H-Frame structures, eight (8) steel single pole structures, two (2) steel three-pole running corners, one (1) steel three-pole dead end structure, two (2) steel switch structures, one (1) 2-way switch, and one (1) new one-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	-	2,167	1,795		3,961
2. Cost of Removal Proposed	-	33	586		619
3. Total Capital and Removal Proposed (1+2)	-	2,200	2,381	-	4,581
4. Capital Investment 2019 BP	-	2,453	-	-	2,453
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	2,453	-	-	2,453
7. Capital Investment variance to BP (4-1)	-	287	(1,795)	-	(1,508)
8. Cost of Removal variance to BP (5-2)	-	(33)	(586)	-	(619)
9. Total Capital and Removal variance to BP (6-3)	-	253	(2,381)	-	(2,127)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the proposed 2020 BP.
This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Bond-Dorchester 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 5,759
   The recommendation is to replace thirty-seven (37) structures and install two (2) new switches during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 8,483
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 6,666
   The next best alternative would be to replace thirty-five (35) structures with wood and two (2) structures with steel. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Bond-Dorchester Pole Replacement project for $4,581k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Corydon-Green River Steel Pole Replacement

Total Capital Expenditures: $6,052k (Including $550k of contingency and $207k of internal labor)

Total O&M: $0k

Project Number(s): 157639

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

<u>Brief Description of Project</u>

The proposed project is to replace one hundred thirty-three (133) existing wood structures on the Corydon-Green River Steel 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred twenty-nine (129) structures identified through a 2018 inspection. The replacement of four (4) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
July 2019	Engineering and Design
October 2019	Space reserved for steel pole production with manufacturer
January 2020	Steel Poles Ordered to Inventory
March 2020	Steel Poles Received to Inventory
April 2020-January 2020	Preliminary services, vegetation clearing, and material holding site completed
March 2021	Steel Poles Charged from Inventory
April 2021	Line Construction Begins
October 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $5,658k, with estimated spend of $453.7k in 2019 and $5,204.6k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined. This project was included in the 2020 BP for $5,690k, with estimated spend of $950k in 2020 and $4,740k in 2021. Subsequent to the 2020 BP, four (4) structures were identified to be replaced in order to accommodate the height of the new structures. In addition, funding was included for a material holding site. The current total project cost is $6,052k, with estimated spend of $950k in 2020 and $5,102k in 2021. 2020 spend is included in the proposed 2020 BP. Incremental spend in 2021 will be addressed in the 2021 BP.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and one hundred twenty-nine (129) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. Four (4) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing one hundred twenty-six (126) steel Z-Frame structures, four (4) steel single pole running corners, one (1) steel single pole dead end structure, and (2) steel single pole structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	950	4,771		5,721
2. Cost of Removal Proposed	-	-	331		331
3. Total Capital and Removal Proposed (1+2)	-	950	5,102	-	6,052
4. Capital Investment 2019 BP	454	5,205	-	-	5,658
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	454	5,205	-	-	5,658
7. Capital Investment variance to BP (4-1)	454	4,254	(4,771)	-	(63)
8. Cost of Removal variance to BP (5-2)	-	-	(331)	-	(331)
9. Total Capital and Removal variance to BP (6-3)	454	4,254	(5,102)	-	(394)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Corydon-Green River Steel 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,410
   The recommendation is to replace one hundred thirty-three (133) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 11,208
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 7,911
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Corydon-Green River Steel Pole Replacement project for $6,052k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Imboden-Gorge-Dorchester

Total Capital Expenditures: $5,996k (Including $545k of contingency and $183k of internal labor)

Total O&M: $0k

Project Number(s): 157642

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Gary King/Adam Smith

Brief Description of Project
The proposed project is to replace forty-two (42) existing wood structures with twenty-six (26) steel structures and sixteen (16) wood structures on the Imboden-Gorge-Dorchester 69kV line. The scope of work includes the replacement of thirty-nine (39) structures identified through inspection in 2018. In addition, one (1) two-way switch will be installed, and three (3) adjacent structures will be replaced in order to accommodate the height of the new structures. Approximately 75% of the thirty-nine (39) structures will need to be completed energized when they are replaced due to the inability to provide alternate feeds to the distribution substations during construction.

Project Milestones	
June 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
December 2019	Steel Poles Ordered
January 2020	Steel Poles Received
March 2020	Line Construction Begins
June 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $3,367k using an average per structure cost prior to the completion of detailed engineering analysis. This project is included in the proposed 2020 BP (BP) for $6,562k, with estimated spend of $2,352k in 2020 and $4,210k in 2021. Once detailed engineering analysis was completed, the estimates have been further refined. The current total project cost is $5,996k, with spend of $2,350k in 2020, and $3,646k in 2021.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and thirty-nine (39) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, three (3) adjacent structures will be replaced in order to accommodate the height of the new structures. Sixteen (16) of the thirty-nine (39) structures are being replaced with wood due to the pole height resulting from the lack of an existing static wire.

The scope of work consists of installing nineteen (19) H-Frame structures, five (5) three-pole running corners, five (5) three-pole dead end structures, five (5) single pole structures, four (4) single pole running corners, three (3) single pole dead end structures, one (1) switch structure, and one (1) two-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next two years, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	2,203	3,384	-	5,587
2. Cost of Removal Proposed	-	147	261	-	408
3. Total Capital and Removal Proposed (1+2)	-	2,350	3,646	-	5,996
4. Capital Investment 2019 BP	-	3,367	-	-	3,367
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	3,367	-	-	3,367
7. Capital Investment variance to BP (4-1)	-	1,164	(3,384)	-	(2,221)
8. Cost of Removal variance to BP (5-2)	-	(147)	(261)	-	(408)
9. Total Capital and Removal variance to BP (6-3)	-	1,017	(3,646)	-	(2,629)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the proposed 2020 BP.

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks
Without the proposed replacement of the priority poles on the Imboden-Gorge-Dorchester 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,484
   The recommendation is to replace forty-two (42) structures and install one (1) two-way switch. Approximately 75% of the forty-two (42) wood structures will be completed energized when they are replaced. There is no opportunity to complete the project de-energized.

2. Alternative #1: NPVRR: ($000s) 11,105
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 9,940
   The next best alternative would be to replace all forty-two (42) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Imboden-Gorge-Dorchester pole replacement project for $5,996k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: ROR-Spare 345/138 450 MVA Transformer

Total Capital Expenditures: $3,777k (Including $270k of contingency including $0k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): 161045

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Kyle Burns

Brief Description of Project

This proposal recommends the purchase of a new spare 345/138kV, 450 MVA with an 80 MVA tertiary to replace Mill Creek TR5 and TR6 in case of a failure. This purchase ensures adequate reserves of critical transformers which can have a lead time of more than nine months. The transformer will be ordered during late 2019, delivered during 2020, and completed by the end of 2020.

Why is the project needed? What if we do nothing?

In November 2016, the North American Electric Reliability Corporation's (NERC) Reliability Issues Steering Committee (RISC) issued recommendations to the NERC Board of Trustees outlining strategic priorities of risks to the reliable operation of the bulk power system. Extreme natural events (hurricanes, tornadoes, extreme temperatures, geomagnetic disturbances, earthquakes, etc.) and physical security vulnerabilities are two of the nine risk profiles identified. Extreme natural events, physical attacks and fire are examples of threats that, while having a low probability of occurrence, can have a crippling effect on reliability of the electric grid if they occur at certain locations. An evaluation of the loss of certain critical LG&E and KU (LKE) substations was undertaken to determine the vulnerability of the system to extreme events. That analysis shows that loss of certain key facilities could result in the inability to serve all firm load for extended periods of time. As indicated in the RISC report, "resilience and recovery actions can mitigate exposure from multiple risks." One of the primary recommendations from the RISC analysis is to focus on spare equipment strategies both to identify critical equipment and to consider transportation logistics and requirements for replacing critical assets. NERC has identified the limited availability of large power transformers as a "potential issue for critical infrastructure resilience in the United States". While it is not possible to mitigate every threat, utilities should be prepared to recover from the loss of key critical facilities. Maintaining an adequate inventory of long lead, critical spares is a cost-effective measure to help mitigate the threat of low probability high impact event.

Specific to the LKE system, planning studies have indicated that it will take two 345/138kV 450MVA transformers to recover from a disaster scenario where multiple transformers at a critical substation in the Louisville area are destroyed or severely damaged. Currently there are two spare transformers. There is one spare dual voltage (345/161 and 345/138 transformer stored at a rail siding in Shelbyville and this transformer will be installed at Blue lick in early 2020. There is another 345/138kV 450 MVA transformer stored at NAS substation. The dual voltage transformer is proposed to be replaced with a 345/161 voltage unit under another project request. An additional spare transformer in the 345/138 voltage class is recommended so that LKE has adequate spares to recover from a catastrophic event. Additionally, this unit will be designed with a tertiary sized to allow it to replace either Mill Creek TR5 or TR6. This will be the only replacement transformer within the system capable of replacing either of the Mill Creek units.

There are nineteen 345/138kV transformers in service. Since April of 2011, there have been three 345/138kV transformer failures. The Appendix below shows a graph of the ages of the 345kV transformers in the LKE System. This additional spare can be considered not only a spare to recover from a disaster scenario, but it would also be considered an additional spare in the event of loss of two 345kV transformers within a year. This spare transformer will be located to ensure we maintain the ability to get it to as many critical locations as possible within a reasonable time frame.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	936	2,841	-	-	3,777
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	936	2,841	-	-	3,777
4. Capital Investment 2019 BP	-	75	2,290	835	3,200
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	75	2,290	835	3,200
7. Capital Investment variance to BP (4-1)	(936)	(2,765)	2,290	835	(576)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(936)	(2,765)	2,290	835	(576)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in either the 2019 or 2020 Business Plans, however $3,200k was included in project 152615 in the 2019BP for a Spare 345/138kV transformer, as reflected above. 152615 was also included in the 2020BP for $3,253k with all spending in 2021. The 2019 spending will be covered in the 2019 RAC Approved 11+1 forecast and the 2020 spending will be covered in the 2020 RAC Approved 0+12 forecast.

Risks

Alternate transformer designs will be considered to address transportation concerns. An attempt will be made to limit the overall shipping dimensions and weight, which may introduce additional costs.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,178
   It is recommended that a spare 345/138, 450 MVA transformer be purchased to reduce the potential risk to the Transmission system.

2. Alternative #1: NPVRR: ($000s) 5,997
   An alternative to LKE's spare is to purchase a highly optimized transformer specifically designed for High Impact Low Frequency (HILF) events. These types of transformers reduce the installation time by weeks but have a much shorter life due to design. These transformers are new in design true to the nature of the response and reliability has not yet been proven.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not recommended as this is a strategic initiative to mitigate a low probability, very high consequence risk and to ensure adequate spares for the 345/138 kV systems to mitigate the risk of transformer failure from routine causes.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the ROR Spare 345/138 450 MVA Transformer project for $3,777k to ensure adequate reserves of critical transformers.

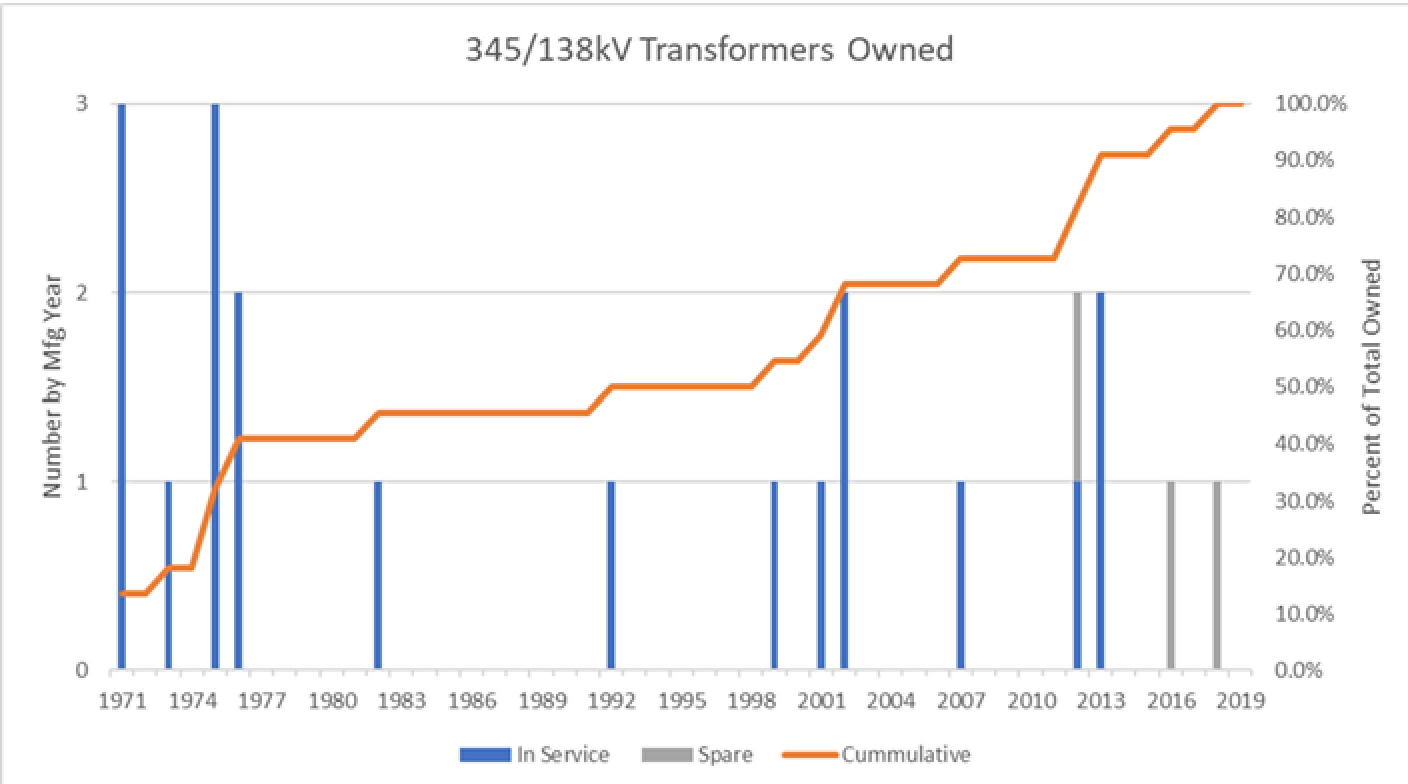
Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

APPENDIX

Age of installed 345/138kV Transformers on the LKE system:



Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: ROR-Spare 345/161 450 MVA Transformer

Total Capital Expenditures: $3,777k (Including $270k of contingency including $0k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): 161044

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Kyle Burns

Brief Description of Project

This proposal recommends the purchase of a new spare 345/161 kV, 450 MVA to replace Alcalde T01, Blue Lick TRANS-2 and Pineville T02 in case of a failure. This purchase ensures adequate reserves of critical transformers which can have a lead time of more than nine months. The transformer will be ordered during late 2019, delivered during 2020, and completed by the end of 2020.

Why is the project needed? What if we do nothing?

In November 2016, the North American Electric Reliability Corporation's (NERC) Reliability Issues Steering Committee (RISC) issued recommendations to the NERC Board of Trustees outlining strategic priorities of risks to the reliable operation of the bulk power system. Extreme natural events (hurricanes, tornadoes, extreme temperatures, geomagnetic disturbances, earthquakes, etc.) and physical security vulnerabilities are two of the nine risk profiles identified. Extreme natural events, physical attacks and fire are examples of threats that, while having a low probability of occurrence, can have a crippling effect on reliability of the electric grid if they occur at certain locations. An evaluation of the loss of certain critical LG&E and KU (LKE) substations was undertaken to determine the vulnerability of the system to extreme events. That analysis shows that loss of certain key facilities could result in the inability to serve all firm load for extended periods of time. As indicated in the RISC report, "resilience and recovery actions can mitigate exposure from multiple risks." One of the primary recommendations from the RISC analysis is to focus on spare equipment strategies both to identify critical equipment and to consider transportation logistics and requirements for replacing critical assets. NERC has identified the limited availability of large power transformers as a "potential issue for critical infrastructure resilience in the United States". While it is not possible to mitigate every threat, utilities should be prepared to recover from the loss of key critical facilities. Maintaining an adequate inventory of long lead, critical spares is a cost-effective measure to help mitigate the threat of low probability high impact event.

Specific to the LKE system, planning studies have indicated that the loss of one of two 345/161 kV 450MVA transformers will cause transmission system issues on the Bulk Electric System

(BES). Currently there is one spare dual voltage (345/161 kV and 345/138 kV) transformer stored at a rail siding in Shelbyville. This transformer will be installed at Blue Lick in early 2020. Therefore, we will not have a 345/161 kV 450 MVA spare after early 2020. An additional spare transformer is recommended so that LKE has adequate spares to recover from a catastrophic event.

Because the existing transformer is dual voltage and provides spare capability for multiple voltage classes, this replacement request is limited to the 345/161 kV voltage class. A second project request will cover the 345/138 kV voltage class. This spare transformer will be located at the Blue Lick transmission substation. to ensure we maintain the ability to get it to critical locations within a reasonable time frame.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	936	2,841	-	-	3,777
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	936	2,841	-	-	3,777
4. Capital Investment 2019 BP	-	-	-	-	-
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(936)	(2,841)	-	-	(3,777)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(936)	(2,841)	-	-	(3,777)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in either the 2019 or 2020 Business Plans. The 2019 spending will be covered in the 2019 RAC Approved 10+2 forecast and the 2020 spending will be covered in the 2020 RAC Approved 0+12 forecast. The 2019BP included a spare 345/138kV transformer however, due to subsequent analysis, this size spare is recommended as well.

Risks

Alternate transformer designs will be considered to address transportation concerns. An attempt will be made to limit the overall shipping dimensions and weight, which may introduce additional costs.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,178
   It is recommended that a spare 345/161 kV, 450 MVA transformer be purchased to reduce the potential risk to the Transmission system.

2. Alternative #1: NPVRR: ($000s) 6,541
   An alternative to LKE's spare is to move the existing dual voltage (345/161:345/138) transformer in service at 345/138 at West Frankfort 211-T01 to any of the following locations Alcalde, Blue Lick or Pineville in case of a failure. It will take 16-20 weeks to disconnect, move and energize the transformer to any of the above locations. Then we will move the spare 345/138 kV transformer at North American Stainless (NAS) to West Frankfort. Then order a new spare to replace NAS.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not recommended as this is a strategic initiative to mitigate a low probability, very high consequence risk and to ensure adequate spares for the 345/161 kV systems to mitigate the risk of transformer failure from routine causes.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Spare 345/161 kV 450 MVA Transformer project for $3,777k to ensure adequate reserves of critical transformers.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: TEP-Blue Lick Transformer Replacement

Total Capital Expenditures: $4,504k

Total O&M: $0k

Project Number(s): Transmission Subs – SU-000347 and 161066

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The existing Blue Lick 345/161kV transformer overloads during planning studies for two different contingencies. A new, higher rated transformer is required to replace the existing transformer and mitigate the overloads. The contingency causing the most severe overload is loss of the Hardin County 345/161 kV transformer and the next worst contingency is loss of the Mill Creek to Hardin County 345 kV line.

The overload of the Blue Lick 345/161 kV transformer was identified in the TEP process and has been reviewed and approved by [redacted], the Company's Independent Transmission Organization (ITO). Operationally, post-contingent overloads have been identified on the Blue Lick 345/161 kV transformer requiring generation redispatch to mitigate.

Overloads under 50/50 and 90/10 winter peak conditions are shown in Table 1 below. This table assumes the proposed Hardin County Project is in service in 2022, which eliminates the violation in 2023 and 2028 for the loss of the Hardin County 345/161 kV transformer. However, the overload still occurs for the loss of the Mill Creek to Hardin County 345 kV line.

Table 1 Post Contingent Loading on Blue Lick 345/161 kV Transformer

Flow Results					
Year	**Contingency**	**50/50 Winter**		**90/10 Winter**	
		Flow (MVA)	**% of Rating**	**Flow (MVA)**	**% of Rating**
2020	Hardin County 345/161 Transformer	324.7	100.20%	340.1	105.00%
2023	Hardin County 345/161 Transformer	274.6	84.80%	290.1	89.50%
2028	Hardin County 345/161 Transformer	284.8	87.90%	301.2	93.00%

Flow Results					
Year	Contingency	50/50 Winter		90/10 Winter	
		Flow (MVA)	% of Rating	Flow (MVA)	% of Rating
2020	Mill Creek to Hardin County 345 kV Line	322.5	99.50%	337.5	104.20%
2023	Mill Creek to Hardin County 345 kV Line	310.5	95.80%	326.6	100.80%
2028	Mill Creek to Hardin County 345 kV Line	320.9	99.00%	336.6	103.90%

The new transformer has a nameplate rating of 450 MVA and provides the needed capacity for summer and winter as shown in Table 2 below.

Table 2: New Ratings

	Winter	Off-Peak	Summer
Normal	585	523	405
Emergency	607	566	515

<u>Project Milestones:</u>

- Preliminary Engineering 2020
- Material in 2021
- Construction in 2021
- Estimated In-Service in May 2021

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Blue Lick 345/161 kV transformer was identified in the TEP process and has also been reviewed and approved by the ITO. This project is required to meet the requirements of NERC Reliability Standard TPL-001-4 and the Company's Planning Guidelines.

Additionally, post-contingent overloads have been identified on the Blue Lick 345/161 kV transformer in operational situations requiring generation redispatch to mitigate.

The overloaded transformer, and contingency that results in the issues are shown in Figure 1 below.

[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	92	1,347	2,830	-	4,269
2. Cost of Removal Proposed	-	-	235	-	235
3. Total Capital and Removal Proposed (1+2)	92	1,347	3,065	-	4,504
4. Capital Investment 2019 BP	-	178	3,126	-	3,304
5. Cost of Removal 2019 BP	-	22	388	-	410
6. Total Capital and Removal 2019 BP (4+5)	-	200	3,513	-	3,714
7. Capital Investment variance to BP (4-1)	(92)	(1,169)	296	-	(965)
8. Cost of Removal variance to BP (5-2)	-	22	152	-	174
9. Total Capital and Removal variance to BP (6-3)	(92)	(1,147)	448	-	(791)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project will utilize a spare transformer that is currently located at Ghent. The net book value of the spare transformer is included in project SU-000347 and the offsetting credit for the same from KU to LG&E is netted with that cost below.

Project	Description	2019	2020	2021	Total
SU-000347	TEP-BL 345/161kV Transf Repl	92	5,050	3,065	8,207
161066	Sale of KU Xfmr to LGE	-	(3,703)	-	(3,703)
	Total	92	1,347	3,065	4,504

This project was included in the 2020 BP for a total of $4,834k with $229k in 2019, $4,580k in 2020, and $25k in 2021. The shortfalls in 2019 and 2020 will be funded in the 2019 RAC Approved 11+1 and 2020 RAC Approved 0+12 forecasts, respectively. The 2021 spending will be covered in the 2021 BP. The reason for the higher spending is due to the addition of a firewall, breaker, and protection panel upgrades that were not originally estimated.

Risks

Without the recommended transformer replacement, there is risk of violating NERC Reliability Standard TPL-001-4 and the Company’s Planning Guidelines.

Transformer 2 will need Oil Spill Prevention and Preparedness (SPCC) measures added.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,705
   The recommendation is to replace 240 MVA transformer at Blue Lick with a 450 MVA transformer

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates NERC Reliability Standards and the Company's Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 19,926
   An alternative for Blue Lick was to add a second redundant Blue Lick 345/161kV transformer. This alternative includes converting the Blue Lick 345 kV bus into a breaker and a half scheme, and converting the 161 kV bus into a three breaker ring bus.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Blue Lick 345/161 kV transformer replacement project for $4,504k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: TEP-Hoover Cap Bank

Total Capital Expenditures: $2,129k (Including $185k of contingency including $95k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): SU-000445, LI-160527, Distribution 160938

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack, Mgr. Trans Strategy & Planning

Brief Description of Project

Post-contingent voltage violations were first identified at the Lemons Mill and Georgetown 69kV substations during the 2019 Transmission Expansion Plan (TEP). This project will add a 69kV, 36.0 MVAR capacitor at Hoover to eliminate the low voltage violations at Lemons Mill and Georgetown 69kV. This will supply reactive power (VAR) support and improve voltage in the area.

The Lines portion of this project will consist of the installation of two permanent steel dead-end structures going into both sides of the substation, as well as the installation of a temporary line around the west side of the station during construction for the new capacitor bank.

Why is the project needed? What if we do nothing?

Low voltage violations at the Lemons Mill and Georgetown 69 kV substations were identified in the TEP process and violate the Company's approved Planning Guidelines. The project is currently under review by [redacted], the Company's Independent Transmission Organization (ITO).

During 2019 winter peak studies, the loss of the Adams to Georgetown 69kV line results in low voltages below the acceptable threshold. This violation also occurs in the winter of 2020 for the loss of the Georgetown to Lemons Mill 69kV line. [redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	90	2,015	18	-	2,123
2. Cost of Removal Proposed	-	7	-	-	7
3. Total Capital and Removal Proposed (1+2)	90	2,022	18	-	2,129
4. Capital Investment 2019 BP	177	903	-	-	1,080
5. Cost of Removal 2019 BP	42	112	-	-	155
6. Total Capital and Removal 2019 BP (4+5)	219	1,016	-	-	1,234
7. Capital Investment variance to BP (4-1)	87	(1,112)	(18)	-	(1,043)
8. Cost of Removal variance to BP (5-2)	42	106	-	-	148
9. Total Capital and Removal variance to BP (6-3)	129	(1,006)	(18)	-	(895)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was partially included in the 2019BP in project SU-000349 TEP Lemons Mill 69kV Cap Bank which was cancelled and replaced by this project. The 2019 spending was approved in the 9+3 RAC approved forecast. Of the three projects, SU-000445 was the only project included in the 2020BP with spending in 2019 ($578k) and 2020 ($617k). The 2020 shortfall will be covered by the 2020 RAC Approved 0+12 forecast. The 2021 spending will be included in the 2021 BP.

	Trans Subs SU-000445	Trans Lines LI-160527	Distribution 160938	Total
Company Labor	47	19	28	94
Materials	418	90	17	525
Contract Labor	735	248	-	983
Contingency	143	42	-	185
Other	-	-	10	10
Burdens	235	68	29	332
	1,578	467	84	2,129

Risks

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project. If the project is completed outside of the optimal window there is a risk of customers experiencing low voltages during winter peak conditions if the critical contingency were to occur. However, this risk can be mitigated by increasing generation at the Brown Plant during the contingency in the near term – but generation redispatch such as this is not an acceptable long term solution per our Planning Guidelines.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 2,381
   Install a capacitor at Hoover 69kV

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   The alternative of Do Nothing puts the customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 7,743
   Add a second 69kV line from Adams – Lemons Mill.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-Hoover 69kV Cap Bank project for $2,129k to reliably serve customers in the Lemons Mill and Georgetown area and to meet the LG&E/KU Planning Guidelines in a least cost manner.

<u>Approval Confirmation for Capital Projects Greater Than $2 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Appendix – Exhibit A

[redacted]

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Transmission Blankets - 2020

Total Expenditures: $3,723k

Project Number(s): Various

Business Unit/Line of Business: Transmission

Prepared/Presented By: Kyle Burns

Brief Description of Project

Transmission uses Blankets to budget and account for annual routine unidentified work. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. Transmission subdivides its Blankets into distinct categories for lines and substations. These categories align with primary work drivers for Transmission.
Annual blanket budgets are based on historical trends and operational input from the managers within Transmission. Blanket spend is monitored and forecast on a monthly basis based on known work identified throughout the year.

Transmission is requesting approval for $3,723k in blankets for 2020, a $12,370k decrease from the 2019 Business Plan for 2020. This decrease is due primarily to moving pole replacement and other lines projects out of blankets and into individually budgeted projects.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2020 Transmission blanket projects for $3,723k to help manage the Transmission work budgeted for 2020.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

CONFIDENTIAL INFORMATION REDACTED

[redacted]

[redacted]

Blanket Description	2020 BP	vs. 2019 BP			vs. 2019 Forecast (9+3)			Variance - 2020 BP vs 2019 Forecast	Projects & Amounts
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		

Investment Proposal for Investment Committee Meeting on: January 29, 2020

Project Name: Olin-Tip Top Conductor Replacement

Total Capital Expenditures: $15,770k (Including $1,413k of contingency and $516k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: Phase I – 148822 & Phase II – LI-160418
Distribution Operations: 159680

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace 13.1 miles of overhead transmission line with conductor that is over 90+ years old and beyond its expected useful life. Performance of this line has diminished, with the most recent conductor failure occurring in 2019. Louisville Gas and Electric Brandenburg substation serves over 1,400 customers with 6.0 MVA of load. In addition, Monument Chemical substation serves 8.2 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to [redacted].

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 13.1 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Tip Top-Brandenburg-Monument Chemical 69kV line in two phases. The existing conductor will be replaced with 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, one hundred seventy eight (178) wood structures will be replaced with new steel structures. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

Project Milestones – Transmission Lines	
July 2018-July 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
March 2020	Steel Poles Received
June 2020	Line Construction Begins
September 2021	Line Construction Completed

Project Milestones – Distribution Operations	
June 2019	Engineering and Design
March 2020	Materials Ordered
March 2020	Materials Delivered
April 2020	Construction Start
December 2021	Construction Completed

	Transmission Lines	Distribution Operations	Total
Total 2019	$549k	$0k	$549k
Total 2020	$4,962k	$558k	$5,520k
Total 2021	$9,027k	$674k	$9,701k
Project Total	$14,538k	$1,232k	$15,770k
Contingency	10%	8%	

<u>Why is the project needed? What if we do nothing?</u>

The existing 13.1 miles of 69kV line between Tip Top-Brandenburg and Brandenburg-Monument Chemical substations contains the original 3/0 ACSR conductor installed in 1925. Non-destructive testing was performed on the conductor in October 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 90% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. This circuit has experienced a total of 21 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, weather, vegetation, and component failures. The most recent event occurred in March 2019 and was caused by a conductor failure. In addition, a routine inspection was completed in 2019 and one hundred twenty-two (122) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System.

In July of 2019, the transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

Approximately half of the conductor rebuild is within rolling hills and wooded terrain, while the remaining portion runs along rural and relatively sparse residential properties. Structures lie on both private, public, and federal lands. Company owned easement, KYTC owned road right of way, and leased property from Fort Knox will be used to access the structures.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.

The structure design consists of one hundred sixty-seven (167) steel single pole structures, two (2) steel three-pole dead end structures, three (3) steel single pole dead end structures, one (1) custom steel metering structure, two (2) steel self-supporting structures, and three (3) steel H-frame structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	546	4,362	8,137	-	13,045
2. Cost of Removal Proposed	4	1,158	1,564	-	2,725
3. Total Capital and Removal Proposed (1+2)	549	5,520	9,701	-	15,770
4. Capital Investment 2020 BP	331	4,403	9,128	-	13,862
5. Cost of Removal 2020 BP	-	577	1,408	-	1,985
6. Total Capital and Removal 2020 BP (4+5)	331	4,980	10,535	-	15,846
7. Capital Investment variance to BP (4-1)	(215)	41	991	-	817
8. Cost of Removal variance to BP (5-2)	(4)	(581)	(156)	-	(740)
9. Total Capital and Removal variance to BP (6-3)	(219)	(540)	835	-	76

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

2019 spend was approved by the Corporate Resource Allocation Committee. Incremental spend in 2020 will be funded by a reduction in other capital projects. Spend in 2021 will be addressed in the 2021 BP.

Risks

- Without the proposed replacement of the existing conductor in the Tip Top-Brandenburg-Monument Chemical 69kV line, the company risks increased exposure to line outages. The conductor along the 13.1 mile section has deteriorated over time and is beyond its expected useful life. There have been notable failures in the conductor's 90+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
- A single overhead transmission failure would impact over 1,300 customers, reducing their reliability until the repairs are complete.

- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
  - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 18,483
   The recommendation is to replace 13.1 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, one hundred seventy-eight (178) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 22,008
   The Next Best Alternative would be to construct a new 15 mile transmission line. Constructing a new route would require the purchase of new right of way customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Olin-Tip Top conductor replacement project for $15,770k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: January 29, 2020

Project Name: REL Hartford-Big Rivers Interconnection Right of Way

Total Capital Expenditures: $658k (Including $60k of contingency and $6k of internal labor)

Total O&M: $0k

Project Number(s): LI-160379

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

Brief Description of Project

This right of way (ROW) purchase project is necessary to complete a larger transmission reliability project (REL Hartford-Big Rivers Interconnection – LI-159067) to be proposed in the next month or two. This ROW purchase project is being proposed to the Investment Committee prior to the larger reliability project to ensure adequate time for ROW acquisition and maintain the schedule of the reliability project.

The reliability project will propose construction of a new 69kV transmission line of approximately 2 miles in length from the Company's Hartford substation and interconnect with [redacted] The new interconnection will be operated with an open switch under normal conditions. Cost estimates for this reliability project are still being developed; however, the current estimate is about $3,000k and incremental to this ROW purchase project.

The reliability project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. The Ohio County to Hartford line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and eliminate future SAIDI events for these customers. In addition, the new interconnection will allow us to perform maintenance or upgrades along the existing Ohio County to Hartford 69 kV line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that additional load at risk.

[redacted] has already agreed to allow the interconnection. A Transmission Lines Access Agreement was signed on October 28, 2019 to allow LG&E and KU site access to [redacted] equipment and connect the new 69kV tap (Hartford Tap) to their Beda-Centertown 69kV line. A revised Interconnection Agreement (IA) with [redacted] will be executed and filed with FERC prior to the energization of the new interconnection. Kentucky PSC approval is not required for construction of the new line.

This project was included in the proposed 2020 BP for $100k with all spend to occur in 2019. Subsequent to the 2020 BP, the estimates have been further refined. Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects.

[redacted]

[redacted]

[redacted]

Why is the project needed? What if we do nothing?

This ROW purchase is needed to support a transmission project to improve reliability to 3,700 customers by providing an alternative source from a new interconnection with [redacted]. The existing KU Beaver Dam, Beaver Dam North, and Hartford substations are served from the 7.14 mile long Ohio County to Hartford radial line, which is historically a very poor performing line. [redacted]. The new interconnection is expected to significantly improve customer reliability and enhance the customer experience. Customers are likely to experience many interruptions in the future without this project.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1	657	-	-	658
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1	657	-	-	658
4. Capital Investment 2020 BP	100	-	-	-	100
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	100	-	-	-	100
7. Capital Investment variance to BP (4-1)	99	(657)	-	-	(558)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	99	(657)	-	-	(558)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

1. Acquisition costs could be higher than the estimates provided in this proposal.
2. Time to acquire the ROW could delay construction of the new interconnection. This could occur from opposition to the new line, and/or landowner negotiations.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the REL Hartford-Big Rivers Interconnection Right of Way project for $658k to support the REL Hartford-Big Rivers Interconnection project.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: January 29, 2020

Project Name: Tip Top-Monument Chemical Pole Replacement

Total Capital Expenditures: $4,860k (Including $442k of contingency and $21k of internal labor)

Total O&M: $0k

Project Number(s): LI-159222

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace seventy-two (72) existing wood structures with new steel structures on the Tip Top-Monument Chemical 69kV line during a scheduled outage. The scope of work includes the replacement of sixty-one (61) structures identified through inspection. Eleven (11) structures will be replaced in order to accommodate the height of the new structures.

Project Milestones	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
February 2020	Steel Poles Received
March 2020	Line Construction Begins
July 2020	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2019 and sixty-one (61) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, eleven (11) structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing sixty-two (62) steel horizontal post framesets, five (5) steel guyed running corners, and five (5) steel guyed vertical dead end structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	248	3,909	-		4,157
2. Cost of Removal Proposed	29	675	-		703
3. Total Capital and Removal Proposed (1+2)	276	4,584	-	-	4,860
4. Capital Investment 2020 BP	264	5,119	-	-	5,383
5. Cost of Removal 2020 BP	3	735	-	-	738
6. Total Capital and Removal 2020 BP (4+5)	267	5,854	-	-	6,121
7. Capital Investment variance to BP (4-1)	16	1,210	-	-	1,226
8. Cost of Removal variance to BP (5-2)	(26)	60	-	-	35
9. Total Capital and Removal variance to BP (6-3)	(9)	1,270	-	-	1,261

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

2019 spend was approved by the RAC. 2020 spend is included in the 2020 Business Plan.

Risks

Without the proposed replacement of the priority poles on the Tip Top-Monument Chemical 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,893
   The recommendation is to replace seventy-two (72) wood structures with steel during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 9,013
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 6,278
   The next best alternative would be to replace all seventy-two (72) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Tip Top-Monument Chemical pole replacement project for $4,860k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: February 27, 2020

Project Name: Harlan Y-Pocket 69kV Pole Replacement

Total Capital Expenditures: $10,022k (Including $911k of contingency and $138k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: LI-158881
Distribution Operations: CRPOLE416

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Brief Description of Project

The proposed project is to replace eighty-two (82) existing wood structures with steel on the Harlan Y-Pocket 69kV line. The scope of work includes the replacement of fifty-three (53) structures identified through inspection in 2018. In addition, twenty-nine (29) adjacent structures will be replaced in order to accommodate the height of the new structures. Due to the difficulty in obtaining an extended outage, approximately 50% of the eighty-two (82) structures will need to be completed energized when they are replaced.

Of the eighty-two (82) structures being replaced, sixty-five (65) are in Kentucky, and seventeen (17) are in Virginia. A Certificate of Public Convenience and Necessity was not required for this project.

Project Milestones – Transmission Lines	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
March 2020	Steel Poles Ordered
May 2020	Steel Poles Received
June 2020	Line Construction Begins
June 2021	Line Construction Completed

Distribution Operations will provide the layout work and transferring of underbuilt distribution where needed.

Project Milestones – Distribution Operations	
February 2020	Engineering and Design
March 2020	Materials Ordered
May 2020	Materials Received

June 2020	Construction Start
November 2020	Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine inspection of the Harlan Y-Pocket 69kV line was completed in 2018, and fifty-three (53) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, twenty-nine (29) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing forty-four (44) steel H-frame structures, twenty-four (24) steel 3-pole dead end structures, three (3) steel 3-pole angle structures, three (3) steel single pole dead end structures, two (2) steel single pole angle structures, and six (6) steel single pole tangent structures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	3,605	5,505	-	-	9,110
2. Cost of Removal Proposed	395	517	-	-	912
3. Total Capital and Removal Proposed (1+2)	4,000	6,022	-	-	10,022
4. Capital Investment 2020 BP	3,337	2,654	-	-	5,990
5. Cost of Removal 2020 BP	664	323	-	-	987
6. Total Capital and Removal 2020 BP (4+5)	4,001	2,977	-	-	6,977
7. Capital Investment variance to BP (4-1)	(268)	(2,852)	-	-	(3,120)
8. Cost of Removal variance to BP (5-2)	269	(194)	-	-	75
9. Total Capital and Removal variance to BP (6-3)	1	(3,045)	-	-	(3,044)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Subsequent to the 2020 BP, detailed engineering was completed and eight (8) additional structures were identified for replacement to accommodate the height increases of the new structures. Detailed engineering also identified that thirteen (13) of the defective structures needed to be converted from suspension to tension structures supported by down guys. In addition, 50% of the structures will be replaced energized, and additional funding was identified for controls required to comply with a detailed environmental assessment for work to be completed in Virginia. Incremental funding in 2021 will be addressed in Transmission's 2021 Business Plan.

	Transmission Lines	Distribution Operations	Total
Total 2020	$3,987k	$13k	$4,000k
Total 2021	$6,008k	$14k	$6,022k
Project Total	$9,995k	$27k	$10,022k
Contingency	10%	10%	

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Harlan Y-Pocket 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $12,517
   The recommendation is to replace eighty-two (82) existing wood structures with steel. Approximately 50% of the eighty-two (82) structures will be completed energized when they are replaced. If the opportunity to replace the structures de-energized would occur, it would reduce the project cost by $505k and the NPVRR by $610k.

2. Alternative #1: NPVRR: ($000s) $18,559
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) $15,101
   The next best alternative would be to replace all eighty-four (84) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Harlan Y-Pocket pole replacement project for $10,022k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: February 27, 2020

Project Name: REL Hartford-Big Rivers Interconnection

Total Capital Expenditures: $3,214k (Including $292k of contingency and $118k of internal labor)

Total O&M: $0k

Project Number(s): LI-159067 – Transmission Lines
161498 – Distribution Operations
LI-160379 – Transmission Lines Easement Acquisition

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

Brief Description of Project

This reliability project proposes construction of a new 69kV transmission line, approximately two miles in length, from the Company's Hartford substation to a new interconnect with an existing 69kV line within [redacted] The new interconnection will be operated with an open switch under normal conditions. The new switch will have remote monitoring and control capability.

The project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. This line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and potentially eliminate future SAIDI events for these customers. In addition, the new interconnection will allow the Company to perform maintenance or upgrades along this line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that load at risk in the future.

[redacted] has already agreed to allow the interconnection. A Transmission Lines Access Agreement was signed on October 28, 2019 to allow LG&E and KU site access to BREC equipment and connect the new 69kV tap (Hartford Tap) to their Beda-Centertown 69kV line. A revised Interconnection Agreement (IA) with [redacted] will be executed and filed with FERC prior to the energization of the new interconnection. Kentucky PSC approval is not required for construction of the new line.

This project was approved for $98k in February of 2019 for preliminary engineering to ensure the project could remain on schedule to meet the desired in-service date. Separately, the project for the easement acquisition (LI-160379) was approved by the Investment Committee in January of 2020 for funding in the amount of $658k.

	Transmission Lines	Distribution Operations	Transmission Lines Easement Acquisition	Total
Total 2019	$155k	$0k	$1k	$156k
Total 2020	$1,301k	$40k	$657k	$1,998k
Total 2021	$1,060k	$0k	$0k	$1,060k
Project Total	$2,516k	$40k	$658k	$3,214k
Contingency	10%	10%	10%	

Transmission Lines will install 2.14 miles of new 69kV line beginning at the Hartford substation and interconnect with Big Rivers. Also included in the scope of this project is the installation of thirty-two (32) new steel structures, a motor operated switch at the new tap point, and two motor operated switches at the Hartford tap. In addition, Telecom has requested the installation of OPGW to eliminate the temporary radio link for communications.

Project Milestones – Transmission Lines	
September 2019	Engineering and Design
March 2020	Materials Ordered
September 2020	Materials Received
September 2020	Construction Start
June 2021	Construction Completed

Distribution Operations will provide the layout work and the transfer of underbuilt distribution conductors where needed.

Project Milestones – Distribution Operations	
January 2020	Engineering and Design
February 2020	Materials Ordered
September 2020	Materials Received
September 2020	Construction Start
June 2021	Construction Completed

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Why is the project needed? What if we do nothing?

This project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. The Ohio County to Hartford line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and potentially eliminate future SAIDI events for these customers. In addition, the new interconnection will allow the Company to perform maintenance or upgrades along the existing Ohio County to Hartford 69 kV line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that additional load at risk.

If we do nothing, customers will be put at risk of sustained outages either due to forced outages or when planned work is needed on the Ohio County to Hartford 69 kV line.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	156	1,994	1,016	-	3,166
2. Cost of Removal Proposed	-	4	44	-	48
3. Total Capital and Removal Proposed (1+2)	156	1,998	1,060	-	3,214
4. Capital Investment 2020 BP	176	1,303	702	-	2,181
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	176	1,303	702	-	2,181
7. Capital Investment variance to BP (4-1)	21	(691)	(314)	-	(985)
8. Cost of Removal variance to BP (5-2)	-	(4)	(44)	-	(48)
9. Total Capital and Removal variance to BP (6-3)	21	(695)	(358)	-	(1,033)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2020 overrun will be covered through reductions in other Transmission projects in coordination with the Resource Allocation Committee (RAC). The 2021 overrun will be covered by Transmission in the 2021 BP.

Risks

- Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.
- Acquisition of the required easements could cause schedule delays and/or increase the estimated overall cost of the project when including the previously approved easement acquisition project (LI-160379).

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,050
   Pursue construction of the proposed interconnection with [redacted]. This project is proposed in connection with the approved Transmission System Improvement Plan.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative is not advisable as it puts customer load at risk on an historically poor performing line of the transmission system.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 5,682
   This alternative would construct a new 3.95 mile transmission line which adds incremental costs in addition to the proposed project cost.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the REL Hartford-Big Rivers Interconnection project for $3,214k to improve customer reliability.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Investment Proposal for Investment Committee Meeting on: April 28, 2020

Project Name: Dorchester-St Paul Pole Replacement

Total Capital Expenditures: $6,185k (Including $562k of contingency including $112k of internal labor)

Total O&M: $ 0 k

Project Number(s): 157636

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

Brief Description of Project

The proposed project is to replace fifty (50) wood structures, on the Dorchester to St Paul 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of fifty (50) structures identified through inspection in 2017.

All fifty (50) structures are located in Virginia. A Certificate of Public Convenience and Necessity is not required for this work.

Project Milestones – Transmission Lines	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
May 2020	Steel Poles Ordered
December 2020	Steel Poles Received
February 2021	Line Construction Begins
August 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine climbing inspection was completed in 2017, and fifty (50) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing three (3) steel single pole dead end structures, four (4) double circuit steel H-frame structures, twenty-three (23) standard steel H-frame structures, six (6) steel three-pole running corners, one (1) steel single pole running corner, five (5) two-pole tangent H-frame structures, six (6) three-pole dead end structures, and two (2) steel light angle H-frame structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1,291	4,058	-	-	5,349
2. Cost of Removal Proposed	-	836	-	-	836
3. Total Capital and Removal Proposed (1+2)	1,291	4,894	-	-	6,185
4. Capital Investment 2020 BP	65	4,894			4,960
5. Cost of Removal 2020 BP	-	1,060			1,060
6. Total Capital and Removal 2020 BP (4+5)	65	5,954	-	-	6,019
7. Capital Investment variance to BP (4-1)	(1,226)	837	-	-	(390)
8. Cost of Removal variance to BP (5-2)	-	224	-	-	224
9. Total Capital and Removal variance to BP (6-3)	(1,226)	1,060	-	-	(166)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 was approved by RAC in the 2+10 forecast.

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Dorchester to St. Paul 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 7,605
   The recommendation is to replace all fifty (50) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 11,454
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 9,530
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Dorchester-St Paul pole replacement project for $6,185k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: May 26, 2020

Project Name: Corydon-Green River Steel Pole Replacement

Total Capital Expenditures: $4,924k (Including $448k of contingency and $99k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161860

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred eleven (111) existing wood structures on the Corydon-Green River Steel 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred five (105) structures identified through a 2018 inspection. The replacement of six (6) adjacent structures is required to accommodate the height of the new structures.

Of the structures being installed, there are ninety seven (97) steel Z-Frame structures, eight (8) steel standard H-frame structures, five (5) steel single pole running corners, and one (1) custom steel dead end H-frame structure.

Project Milestones	
March 2020	Engineering and Design
June 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered to Inventory
December 2020	Steel Poles Received to Inventory
January 2021-April 2021	Preliminary services, vegetation clearing, and material holding site completed
April 2021	Steel Poles Charged from Inventory
May 2021	Line Construction Begins
December 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and one hundred five (105) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Six (6) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	4,570	-	-	4,570
2. Cost of Removal Proposed		353	-	-	353
3. Total Capital and Removal Proposed (1+2)	-	4,924	-	-	4,924
4. Capital Investment 2020 BP	-	-	4,924	-	4,924
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	4,924	-	4,924
7. Capital Investment variance to BP (4-1)	-	(4,570)	4,924	-	353
8. Cost of Removal variance to BP (5-2)	-	(353)	-	-	(353)
9. Total Capital and Removal variance to BP (6-3)	-	(4,924)	4,924	-	0

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2020 Business Plan (BP) under project K9-2022. This project is being accelerated as part of the 2021 BP, supporting efforts to address the defective transmission pole backlog. The spend in 2021 will be addressed in the 2021 BP.

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Corydon-Green River Steel 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 6,348
   The recommendation is to replace one hundred eleven (111) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 9,118
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 6,647
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Corydon-Green River Steel Pole Replacement project for $4,924k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: May 26, 2020

Project Name: Pineville-Rocky Branch Right of Way

Total Capital Expenditures: $2,977k (Including $466k of contingency and $30k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161704

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith

Brief Description of Project

Transmission Lines seeks funding authority of $2,977k to acquire the permanent easement rights of way for the existing Pineville-Cary- Rocky Branch 69kV transmission circuit.

In 1923 the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the Pineville-Cary-Rocky Branch circuit that currently consists of 16.51 miles of line and 106 structures. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a concern at that time regarding the rule against perpetuity which does not exist anymore in case law. This project will acquire permanent easement ROW in Bell County for the existing Pineville-Cary-Rocky Branch 69kV circuit. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate this transmission line and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements expire in 2023 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $100k for surveying and land evaluation services in April of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research along the Pineville-Cary-Rocky Branch line that discovered the entire circuit's land access rights were covered under separate 99-year leases. The current lease agreement, which cover 91 parcels with 74 different landowners, will expire in 2023. At that time the Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities.

As a result of additional preliminary research, the 99-year ROW lease issue was discovered on the KU Park - Middlesboro 69kV and KU Park - Bimble 69kv transmission lines. Separate approval will be sought for those projects. At this time no additional transmission lines originating from the Pineville area were determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	685	2,292	-	-	2,977
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	685	2,292	-	-	2,977
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(685)	(2,292)	-	-	(2,977)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(685)	(2,292)	-	-	(2,977)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in the 2020 Business Plan (BP). The need for this project was discovered after the 2020 BP was complete. Funding in 2020 was included in the RAC approved 3+9 forecast. Funding in 2021 will be addressed by Transmission in the 2021 BP.

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $6.5k per acre was utilized for easement cost estimates. A property valuation assessment will be completed as part of the project to refine this figure but is not able to be completed at this time due to the closure of the county clerk's office as a result of the COVID-19 pandemic. Additionally, a 5% assumption was utilized to calculate the number of condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,578
   Secure the permanent easement ROW for the Pineville-Cary-Rocky Branch 69kV circuit. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in Company having to wait to fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property that the circuit exists. This approach carries and unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, one (1) landowner is aware of this issue as a result of the 2019 encroachment issue and has inquired about this issue. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 42,015
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option from that perspective either.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Pineville-Rocky Branch ROW project for $2,977k to support future line maintenance and construction along the Pineville-Cary-Rocky Branch 69kV circuit.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: June 30, 2020

Project Name: Morganfield-Nebo Static Replacement

Total Capital Expenditures: $5,486k (Including $490k of contingency and $217k of internal labor)

Total O&M: $ 150 k related to Telecom

Project Number(s): 148854

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Ronnie Bradford/Adam Smith

Brief Description of Project

The proposed project is to replace 23.5 miles of static wire that is over 90+ years old and beyond its expected useful life. Performance of this wire has diminished, with the most recent failure occurring in 2014. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Earlington, Nebo, and Morganfield areas.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 23.5 miles of 3/8" steel static between the Morganfield and Nebo substations with optical ground wire (OPGW). In addition, steel static peaks will be replaced on eighty-five (85) of the existing steel towers and three (3) lattice towers will be replaced with steel poles. This project also includes a complete below grade inspection and coatings for all tower legs, with tower member reinforcements when required. This work will be completed during a scheduled outage.

In February of 2019, this transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and the development of the construction plan. The transmission line design was provided to all departments involved for review.

Project Milestones – Transmission Lines	
February 2019-May 2020	Engineering and Design
July 2020	Materials Ordered
August 2020-September 2020	Steel Poles Received
October 2020	Line Construction Begins
April 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

The existing 23.5 miles of 69kV line between Nebo and Morganfield substations contains the original 3/8" static wire installed in 1927. Aerial patrol inspections of this line revealed that the existing static wire is in poor mechanical condition and has reached the end of its useful life. The wire has corroded, become brittle, and does not have its original design strength. Due to the conditions of this wire, there is a risk of additional failures that will expose the transmission network to further unscheduled outages.

This project will complete the fiber path from Earlington North to Nebo to Morganfield. The 13.2 miles between Earlington North and Nebo were completed on a previous project (Project 147999 Earlington North-Nebo static replacement). Completion of this route will support Telecom's efforts to offset expensive leased line costs currently being used for the Morganfield Call Center. Transitioning to a company owned fiber route will provide greater network bandwidth to the Morganfield Call Center and office, the capability to expand the internal network throughout the Morganfield area, and increase the overall reliability as compared to the existing leased line. The company will also have greater control over making any necessary repairs to the fiber path from damage occurring during major system events. In addition, this communication path could potentially be provided for Distribution Automation, and other use cases for 5 additional substations.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	31	1,701	3,288	-	5,020
2. Cost of Removal Proposed			466	-	466
3. Total Capital and Removal Proposed (1+2)	31	1,701	3,754	-	5,486
4. Capital Investment 2020 BP	26	1,387	1,529	-	2,941
5. Cost of Removal 2020 BP	-	179	269	-	448
6. Total Capital and Removal 2020 BP (4+5)	26	1,566	1,798	-	3,389
7. Capital Investment variance to BP (4-1)	(5)	(314)	(1,759)	-	(2,079)
8. Cost of Removal variance to BP (5-2)	-	179	(197)	-	(18)
9. Total Capital and Removal variance to BP (6-3)	(5)	(135)	(1,956)	-	(2,097)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	56	56	22	15	150
2. Project O&M 2020 BP	56	56	56	169	338
3. Total Project O&M variance to BP (2-1)	-	-	34	154	188

Subsequent to the 2020 Business Plan (BP), detailed engineering along with complete scope development increased the planned work for this project. This project now includes a complete below grade inspection and coating for all tower legs. 2020 spend was approved by the

Resource Allocations Committee. 2021 spend will be funded through the reduction of other Transmission projects in the 2021 BP.

The O&M savings of $154k in the Post 2021 column reflects the termination of a leased Telecom DS3 line through AT&T, for the years 2022 through 2024 (at an annual cost of $56k) replaced with approximately $5k annual expenses associated with the OPGW fiber connection. Telecom will reduce the 2021 BP to reflect this savings.

Risks

- Without the proposed replacement of the existing static wire in the Morganfield-Nebo 69kV line, the company risks increased exposure to line outages. The wire along the 23.5 miles has deteriorated over time and is beyond its expected useful life. The wire has corroded and does not have its original design strength. Unplanned outages are often time-consuming and costly when it comes to repairs.
- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.
- Risks associated with project timeline:
    - Winter and early spring weather impacts could pose significant delays, including issues with structure access across agriculture operations.
    - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.
- There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 6,572
   The recommendation is to replace 23.5 miles of static wire with new OPGW. In addition, steel static peaks will be replaced on eighty-five (85) of the existing steel towers and three (3) lattice towers will be replaced with steel poles. The additional expense is a prudent strategic investment in this one-time opportunity to be able to complete a company-owned fiber path between Earlington and Morganfield. This project will allow Telecom to reduce ongoing expense costs associated with the leased communication line and provide the company greater certainty and operational control over the communication path between Earlington and Morganfield.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this wire is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 6,339
   This alternative would be to splice failed sections as needed. Without the proposed replacement of the existing static wire in the Morganfield-Nebo 69kV line, the

company risks increased exposure to line outages due to this 90+ year old asset. If the existing static wire is not replaced, the company risks having to make repairs with an unplanned outage which would add increased costs due to overtime labor. Repairs would involve splicing the failed static wire back together. While the splice does reconnect the damaged wire, repairing the static wire does not address the poor mechanical condition of the wire. This alternative is not recommended because it would forfeit the benefits of the previous OPGW investments on the other section of this line.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Morganfield-Nebo Static Replacement project for $5,486k to improve reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: June 30, 2020

Project Name: TEP-CR-Ashbottom-South Park

Total Capital Expenditures: $3,531k (Including $316k of contingency and $157k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines: 157188 ($3,479k)
Distribution Operations: 162420 ($52k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Ashbottom - South Park 69kV line overloads in planning studies required for the Transmission Expansion Plan (TEP) required by the companies Planning Guidelines. This project was approved by [redacted], the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak conditions, an outage of the Mud Lane 138/69 transformer and Mud Lane 138 kV bus causes the Ashbottom - South Park 69kV line to overload 100.2% in 2020. The overload is 107.1% in 2029. During the 50/50 summer peak conditions, the overload is 100.7% in 2027. Transmission planning guidelines require a corrective action plan when post-contingent flows exceed 100% of the emergency rating through the end of the ten year planning horizon.

When the project is completed the summer emergency rating will go from 133 MVA to 143 MVA thus resolving the overload issue. The maximum post-contingent flow will be 93.2% under 90/10 summer peak conditions in 2030 according to the latest TEP models.

This project was opened for preliminary services in March of 2019 for engineering services to further develop the project scope and estimate to support this large capital project.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

Transmission Lines plans to replace 1.4 miles of existing 1272 MCM 61X All Aluminum Conductor with 1272 MCM 45X7 Aluminum Conductor Steel Reinforced, and the existing static wire will be replaced with new optical ground wire. In addition to the conductor and static being replaced, twenty-seven (27) existing wood structures that do not have adequate structural capacity to meet NESC Heavy loading will be replaced with new steel structures. Of these twenty-seven (27) structures, five (5) will be relocated out of a wetland area into the Railroad right of way.

Project Milestones – Transmission Lines	
March 2020-May 2020	Engineering and Design
May 2020	Space reserved for steel pole production with manufacturer
September 2020	Steel Poles Ordered
November 2020	Steel Poles Received
January 2021	Line Construction Begins
November 2021	Line Construction Completed

Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
March 2020-September 2020	Engineering and Design
November 2020	Materials Ordered
November 2020	Materials Delivered
December 2020	Construction Start
November 2021	Construction Completed

Project Cost

	Transmission Lines	Distribution Operations	Total
Total 2020	$114k	$7k	$121k
Total 2021	$3,365k	$45k	$3,410k
Project Total	$3,479k	$52k	$3,531k
Contingency	10%	0%	

<u>Why is the project needed? What if we do nothing?</u>
The overload of the Ashbottom - South Park 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, it will be in violation of the Company's Transmission Planning Guidelines and put customer load at risk.

[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	121	3,092	-	-	3,213
2. Cost of Removal Proposed	-	318	-	-	318
3. Total Capital and Removal Proposed (1+2)	121	3,410	-	-	3,531
4. Capital Investment 2020 BP	117	3,578	-	-	3,696
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	117	3,578	-	-	3,696
7. Capital Investment variance to BP (4-1)	(4)	486	-	-	482
8. Cost of Removal variance to BP (5-2)	-	(318)	-	-	(318)
9. Total Capital and Removal variance to BP (6-3)	(4)	169	-	-	165

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 was covered through reductions to other Transmission projects and approved by the Resource Allocations Committee.

<u>Risks</u>

Without the recommended re-conductor of the Ashbottom - South Park 69kV line, the Company will be in violation of the its Transmission Planning Guidelines and the TEP process. Not completing this project also places customer load at risk of interruption.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,273
   The recommendation is to replace 1.4 miles containing 1272 MCM 61X AA conductor with new 1272 MCM 45X7 ACSR conductor, the existing static wire with OPGW, and the replacement of twenty-seven (27) existing wood structures with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Add Second Transformer NPVRR: ($000s) 8,637
   Add a second 138/69 transformer at Mud Lane and install two 138 kV breakers. One breaker to be installed on the high side of each of the transformers.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TEP-CR-Ashbottom-South Park project for $3,531k to comply with the Company's Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: July 29, 2020

Project Name: Lebanon-Lebanon Upgrade (TEP)
TEP-NL-Lebanon-Lebanon ROW (Lines)

Total Capital Expenditures: $13,004k (Including $1,151k of contingency and $511k of internal labor)

Total O&M: $ 0 k

Project Number(s): Construction ($12,255k)
157211 - Lines Overhead
SU-000425 – Substations Protection and Controls
SU-000440 – Substations Line
162253 – Distribution Operations

Rights of Way ($749k)
LI-160928 – Transmission Lines ROW

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Lebanon-Lebanon South Transmission Expansion Plan (TEP) project is the least cost solution to solve a thermal overload and low voltage problem identified in the Transmission Expansion Plan (TEP). For the loss of either the Lebanon to Lebanon Industrial line or the Lebanon Industrial to Lebanon East line, reliability to approximately nine- thousand customers and 46 MWs of load served in the area is at risk. The overloaded line and area with low voltage are shown in Appendix A.

The Company's Independent Transmission Organization (ITO), [redacted] approved a similar project as part of the 2018 TEP (Alternative #2). The ITO will need to approve the revised project. Notification to the ITO will be provided in July and approval is expected, primarily since the revised project is less expensive.

The project includes construction of a new 2.04 mile 69kV line, utilizing single and double circuit construction, between the existing Lebanon and Lebanon East substations. The new line will consist of the installation of forty (40) new steel structures, the removal of forty (40) wood and five (5) steel structures, and the installation of four (4) new switches with motor operators. While 2.04 miles of new 556 ACSR 26/7 and OPGW will be installed, 0.61 miles of existing conductor will be removed. Kentucky Public Service Commission approval of the new line is not required.

This project was approved for a total of $613k during February 2019 for preliminary engineering services to further identify the project requirements and develop the project scope. A revision was submitted for an additional $89k funding in March of 2020 to allow for preliminary engineering services to continue prior to the Investment Committee meeting scheduled for July of 2020. Separately, the Transmission Lines easement acquisition was approved through the AIP process during October 2019.

LG&E/KU organized a meeting with Marion County judicial personnel and Lebanon City officials to describe the project in June 2020. The feedback from the information meeting was positive.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
January 2020	Space reserved for steel pole production with manufacturer
August 2020	Steel Poles Ordered
March 2021	Steel Poles Received
June 2021	Line Construction Begins
March 2022	Line Construction Completed

Transmission Substations will install a new control house at the Lebanon Substation (#43). This project (associated with project # SU-000425) aligns with the Transmission System Improvement Plan (TSIP) and will provide improvements in protection and control systems at Lebanon (#43). Additionally, the existing house would not accommodate the new line panel required for the TEP project. The scope of work will consist of installing a new DFR panel, a new RTU panel, two (2) new transformer differential panels, two (2) new bus differential panels, two (2) new breaker control panels, four (4) new line relaying panels, as well as two (2) blank panels for telecom equipment in the new control building. In addition, three (3) circuit breakers, six (6) 69kV disconnect switches, one (1) 138kV high voltage switch, and PT junction boxes will also be replaced and connected to the new control house with new cable trench, conduit, and cabling. This additional protection and control project was not part of the TEP, however it is aligned with our TSIP. Completing these projects together will allow for greater resource efficiencies for design and construction.

[redacted] In addition, a new 69kV box structure, circuit breaker, and line terminal will be constructed at the Lebanon Substation to accommodate the new 69kV circuit.

Project Milestones – Transmission Substations	
August 2019-October 2020	Engineering and Design
July 2020	Materials Ordered
June 2021	Materials Received
January 2021	Construction Start
August 2022	Construction Completed

Distribution Operations will provide the layout and transferring of distribution underbuilt where needed.

February 2020-March 2020	Engineering and Design
October 2021	Material Ordered
October 2021	Materials Received
December 2021	Construction Start
Spring 2022	Construction Completed

Why is the project needed? What if we do nothing?

The 2018 TEP identified an overload of the Campbellsville Tap – Taylor County 69kV line and low voltage on the Lebanon Industrial 69kV, Lebanon East substations. This project is needed to eliminate the overload and low voltage situation, safely and reliably serve customer load in the area, and is required per the Company's Transmission Planning Guidelines.

If the project is not constructed, customer load is at risk and the Company is in violation of its Transmission Planning Guidelines, as approved by the ITO.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	418	2,013	6,418	3,364	12,213
2. Cost of Removal Proposed	-	-	643	149	792
3. Total Capital and Removal Proposed (1+2)	418	2,013	7,060	3,513	13,004
4. Capital Investment 2020 BP	282	3,226	8,627	948	13,082
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	282	3,226	8,627	948	13,082
7. Capital Investment variance to BP (4-1)	(136)	1,213	2,209	(2,417)	870
8. Cost of Removal variance to BP (5-2)	-	-	(643)	(149)	(792)
9. Total Capital and Removal variance to BP (6-3)	(136)	1,213	1,567	(2,566)	78

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2022 will be funded by a reduction in other Transmission capital projects.

$000s	Trans Lines Construction 157211	Trans Lines ROW LI-160928	Trans Subs Protection SU-000425	Trans Subs Line SU-000440	Dist Ops 162253	Total
Total 2019	$170	$175	$0	$73	$0	$418
Total 2020	$229	$574	$488	$722	$0	$2,013
Total 2021	$4,193	$0	$1,001	$1,866	$0	$7,060
Total 2022	$1,768	$0	$1,231	$385	$129	$3,513
Project Total	$6,360	$749	$2,720	$3,046	$129	$13,004
Contingency	10%	5%	10%	9%	10%	

This project contains a 9% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 14,422
   As described above.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative is not recommended since it puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Alternate Route NPVRR: ($000s) 22,571
   The alternative would consist of the construction of a new 4.25 mile 69kV line, utilizing single and double circuit construction, between the existing Lebanon and Lebanon South substations. In addition, a new transmission switching station would be constructed near Lebanon South to include a 69kV low profile, four breaker ring bus with line exits to Taylor County, Lebanon Intercounty REA, Lebanon and Lebanon South.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Lebanon-Lebanon Upgrade project for $13,004k to improve reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

CONFIDENTIAL INFORMATION REDACTED

[redacted]

CONFIDENTIAL INFORMATION REDACTED

[redacted]

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Investment Proposal for Investment Committee Meeting on: August 27, 2020

Project Name: Lebanon-Taylor County Pole Replacement

Total Capital Expenditures: $5,939k (Including $540k of contingency and $252k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines - LI-161721 ($5,784k)
Distribution Operations – 163507 ($155k)

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Tony Mount/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred fifteen (115) existing wood structures with steel structures on the Lebanon-Taylor County 69kV line during a scheduled outage. The scope of work includes the replacement of ninety-nine (99) structures identified through inspection in 2019. In addition, sixteen (16) adjacent structures will be replaced in order to accommodate the height of the new structures.

In July of 2020, this transmission project was opened for $726k to support preliminary engineering for project scope and development, and vegetation clearing.

Project Milestones – Transmission Lines	
July 2020	Engineering and Design
July 2020	Space reserved for steel pole production with manufacturer
September 2020	Steel Poles Ordered
December 2020	Steel Poles Received to Inventory
January 2021	Steel Poles Charged from Inventory
January 2021	Line Construction Begins
June 2021	Line Construction Completed

Distribution Operations will provide the layout work and transferring of underbuilt distribution where needed.

Project Milestones – Distribution Operations	
May 2020-July 2020	Engineering and Design
January 2021	Materials Charged from Inventory
January 2021	Construction Start
July 2021	Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine inspection of the Lebanon-Taylor County 69kV line was completed in 2019, and ninety-nine (99) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, sixteen (16) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing ninety-three (93) steel single pole tangent structures, seven (7) steel single pole angle structures, and fifteen (15) steel H-frame tangent structures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	48	5,135	-	-	5,183
2. Cost of Removal Proposed	-	756	-	-	756
3. Total Capital and Removal Proposed (1+2)	48	5,891	-	-	5,939
4. Capital Investment 2020 BP	-	-	-	6,419	6,419
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	6,419	6,419
7. Capital Investment variance to BP (4-1)	(48)	(5,135)	-	6,419	1,236
8. Cost of Removal variance to BP (5-2)	-	(756)	-	-	(756)
9. Total Capital and Removal variance to BP (6-3)	(48)	(5,891)	-	6,419	480

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2020 Business Plan (BP) under project K9-2025 for $6,419k. This project is being accelerated as part of the 2021 BP, supporting efforts to limit forced outage risks while the Lebanon-Lebanon Upgrade project (157211) is being constructed. 2020 spend was covered through reductions in other Transmission projects and approved by the Resource Allocations Committee. The spend in 2021 will be covered through reductions in other Transmission projects within 2021 BP. The project contains a 10% contingency ($526k- Lines and $14k-Distribution) which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

	Transmission Lines	Distribution Operations	Total
Total 2020	$48k	$0k	$48k
Total 2021	$5,736k	$155k	$5,891
Project Total	$5,784k	$155k	$5,939k
Contingency	10%	10%	

Risks

Without the proposed replacement of the priority poles on the Lebanon-Taylor County 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $7,183
   The recommendation is to replace one hundred fifteen (115) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) $11,028
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) $7,487
   The next best alternative would be to replace all one hundred fifteen (115) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Lebanon-Taylor County pole replacement project for $5,939k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: September 29, 2020

Project Name: KU Park-Middlesboro Right of Way

Total Capital Expenditures: $1,909k (Including $174k of contingency and $37k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162350

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith/Paul Weis

Brief Description of Project

Transmission Lines seeks funding authority of $1,909k to acquire the permanent easement rights of way for the existing KU Park-Middlesboro 69kV transmission circuit.

In 1923, the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the KU Park-Middlesboro circuit that currently consists of 13.1 miles of line and 101 structures. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a concern at that time regarding the rule against perpetuity which does not exist anymore in case law. This project will acquire permanent easement ROW in Bell County for the existing KU Park-Middlesboro 69kV circuit. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate this transmission line and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements begin to expire in 2022 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $110k for surveying and land evaluation services in May of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019 on a near-by transmission line, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research of all the transmission lines originating from the Pineville transmission station (KU Park). The KU Park-Middlesboro line was determined to be covered under separate 99-year leases for access and use rights. The current lease agreements, which cover 84 parcels with 71 different landowners, will begin to expire in 2022. At that time the Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the

Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities.

The 99-year ROW lease issue was discovered on the Pineville-Cary-Rocky Branch 69kV, KU Park - Bimble 69kV, and a 2 mile portion of the Bimble – London 69kV transmission lines. Separate approval will be sought for those projects. At this time no additional transmission lines originating from the Pineville area have been determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	99	1,202	607	-	1,909
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	99	1,202	607	-	1,909
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(99)	(1,202)	(607)	-	(1,909)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(99)	(1,202)	(607)	-	(1,909)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in the 2020 Business Plan (BP). The need for this project was discovered after the 2020 BP was complete. Funding in 2020 was included in the RAC approved forecast. Funding in 2021 and 2022 was addressed by Transmission in the 2021 BP and is funded by reductions in other Transmission capital projects.

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $4,500 per acre was utilized for easement cost estimates based upon the property valuation assessment completed as part of the Pineville – Rock Branch project. Additionally, a 5% assumption was utilized to calculate the number of potential condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,846
   Secure the permanent easement ROW for the KU Park-Middlesboro 69kV circuit. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in Company having to wait to fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property where the circuit exists. This approach carries an unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, area local officials and landowners are aware of this issue and there is local knowledge of this project with the initiation of the Pineville – Rocky Branch project. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 29,037
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Middlesboro ROW project for $1,909k to support future line maintenance and construction along the KU Park-Middlesboro 69kV circuit.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: September 29, 2020

Project Name: Eastwood-Simpsonville Expansion Plan Conductor Replacement

Total Capital Expenditures: $3,791k (Including $350k of contingency including $130k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines – LI-159249 ($3,140k)
Distribution Operations – 163504 ($651k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Eastwood – Simpsonville 69 kV line overloads in planning studies required for the Transmission Expansion Plan (TEP) which in turn are required by the Companies Planning Guidelines. This project was approved by [redacted] the Company's Independent Transmission Organization (ITO).

During the 90/10 and 50/50 customer forecasts for winter peak conditions, an outage of the Blue Lick 345/161kV transformer causes the Eastwood – Simpsonville 69 kV line to overload 106.1% (50/50 2021 winter) and 110.2% (90/10 2021 winter). The overloads remain throughout the ten year planning horizon.

When the project is completed, the winter emergency rating will go from 101 MVA to 141 MVA thus resolving the overload issue for the entire ten year period. The maximum post-contingent flow will be 89.1% (90/10 2029 winter).

This project was opened for preliminary services in June of 2020 for $242k for engineering services to further develop the project scope and estimate to support this capital project.

A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to customers, community, and businesses along the route.

Transmission Lines plans to replace 3.53 miles of existing 397.5 Aluminum Conductor Steel Reinforced (ACSR) with 556.5 (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-two (52) existing wood structures that do not have adequate structural capacity to meet NESC Heavy loading will be replaced with new steel structures.

Project Milestones – Transmission Lines	
June-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered
December 2020	Steel Poles Received
January 2021	Line Construction Begins
June 2022	Line Construction Completed

Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
May-August 2020	Engineering and Design
December 2020	Materials Ordered
January 2021	Materials Delivered
January 2021	Construction Start
August 2021	Construction Completed

Project Cost

	Transmission Lines	Distribution Operations	Total
Total 2020	$246k	$0k	$246k
Total 2021	$2,162k	$651k	$2,813k
Total 2022	$732k	$0	$732k
Project Total	$3,140k	$651k	$3,791k
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Eastwood-Simpsonville 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, customer load will be at risk and it will be in violation of the Company's Transmission Planning Guidelines.

[redacted]

[redacted]

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	185	2,443	664	-	3,292
2. Cost of Removal Proposed	61	369	69	-	499
3. Total Capital and Removal Proposed (1+2)	246	2,812	732	-	3,791
4. Capital Investment 2020 BP	187	3,705	-	-	3,891
5. Cost of Removal 2020 BP	63	570	-	-	633
6. Total Capital and Removal 2020 BP (4+5)	250	4,275	-	-	4,525
7. Capital Investment variance to BP (4-1)	2	1,261	(664)	-	599
8. Cost of Removal variance to BP (5-2)	2	201	(69)	-	134
9. Total Capital and Removal variance to BP (6-3)	4	1,462	(732)	-	734

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2022 is funded by a reduction in other Transmission Capital projects in the proposed 2021 BP.

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

<u>Risks</u>

Without the recommended re-conductor of the Eastwood-Simpsonville 69kV line, the Company will put customer load at risk and be in violation of its Transmission Planning Guidelines and the TEP process.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,610
   Transmission Lines plans to replace 3.53 miles of existing 397.5 Aluminum Conductor Steel Reinforced (ACSR) with 556.5 (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-two (52) existing wood structures will be replaced with new structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Construct New Line NPVRR: ($000s) 23,262
   Build a new 69kV line from the LG&E Middletown 69 kV substation to the KU Finchville 69 kV substation, approximately 12.3 miles. This project would require purchase of new 69kV ROW or expansion of existing 69 kV ROW, all new 69 kV structures, and 795 ACSR MCM conductor or an equivalent. Expansion of both the Middletown and Finchville 69 kV substations to accommodate the additional 69 kV line exits, breakers and all other associated terminal equipment would also be necessary.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Eastwood-Simpsonville project for $3,791k to comply with the Company's Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: PCH, PBR Clark County Proactive Control House and Breaker Replacements

Total Capital Expenditures: $4,090k (Including $348k of contingency including $110k of internal labor)

Total O&M: $ 0k

Project Number(s): SU-000323

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

As part of the Transmission System Improvement Plan (TSIP), this project is a combination of several system integrity programs to address assets in need of replacement at Clark County substation. Clark County has assets operating at 138kV and 69kV that have been in service for longer than 50 years. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events.
- Install Digital Fault Recorder (DFR) for improved system analysis.
- Replace Substation Breakers - Three (3) 69kV and two (2) 138kV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – Five (5) 69kV 3-phase high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age where failure is common, often during operation. Additionally, one (1) 69kV and one (1) 138kV high-side Potential Transformer (PT) fused disconnects will be removed. This equipment is a common point of failure, resulting in an increased risk of bus outages.
- Replace Substation Line Arresters – Two (2) 69kV and two (2) 138kV sets of line surge arresters. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Insulators – Six (6) 3-phase cantilever cap & pin type insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

Why is the project needed? What if we do nothing?

The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	505	390	1,247	1,803	3,944
2. Cost of Removal Proposed	-	-	-	147	147
3. Total Capital and Removal Proposed (1+2)	505	390	1,247	1,949	4,090
4. Capital Investment 2021 BP	261	635	1,247	1,803	3,945
5. Cost of Removal 2021 BP	-	-	-	147	147
6. Total Capital and Removal 2021 BP (4+5)	261	635	1,247	1,949	4,092
7. Capital Investment variance to BP (4-1)	(244)	245	-	-	1
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(244)	245	-	-	1

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This

project will remove two 69kV line panels and one 138kV line panel currently utilizing GCX relays.

- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. Materials suspected to contain asbestos will be managed by qualified personnel.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,173

2. Alternative #1: NPVRR: ($000s) 4,532
The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability. Additionally, it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. This alternative assumes one breaker failure and oil cleanup prior to breaker replacements.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PCH, PBR Clark County project for $4,090k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

[redacted]

[redacted]

Exhibit C: Major Replaced Equipment Age

Equipment	Install Date
Control House	1965
Oil Circuit Breaker 604	1956
Oil Circuit Breaker 614	1965
Oil Circuit Breaker 608	1968
Oil Circuit Breaker 714	1965
Oil Circuit Breaker 724	1957

Investment and Contract Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: Commonwealth Solar Generator Interconnection Agreement and Project
Contract Name (Good/Service): Large Generator Interconnection Agreement – [redacted]

Selected Vendor(s): Not Applicable

Contract Authorization Requested: $ 9,854k (Including $896k of contingency)

Contract Term:

Total Capital Expenditures Requested: $ 9,854k (gross), $8,825k (net) (Including $896k of contingency and $541k of internal labor)
Total O&M: $0k

Project Number(s): 163635 Interconnection Subs, 163640 Network Facilities Subs, and 163641 Network Facilities Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted].

On January 15, 2019 [redacted] (customer) proposed the interconnection of a new 110MW solar generating facility in [redacted]. [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Facilities that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $9,854k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $1,030k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $8,824k.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $9,854k, which includes a 10% contingency. This contingency covers increases in actual costs beyond the estimate. This work is not included in the 2021 BP because the customer indicated they would suspend the agreement upon execution of the LGIA which delays performing the work for up to three years. Funding will be included in future BPs when greater certainty exists that the project will be constructed. [redacted] retains the option to terminate the LGIA; however, the customer must provide acceptable security to ensure LG&E/KU is reimbursed for incurred construction costs if the generation interconnection does not become operational.

Interconnection Facilities
The new interconnection facility will be constructed approximately 0.4 miles south of the Interconnection Customer's (IC's) new generation facility. The interconnection facilities include 138kV structure and equipment necessary to terminate the generator lead line and to provide metering. The IC will be responsible for the design, construction, and permitting of the 138kV transmission line from their interconnection facilities to the Point of Change of Ownership (PCO) at the [redacted]

The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities upon completion of the project.

Network Facilities
The network facilities include a new 138kV interconnection station, a 138kV loop from the existing Brown Plant to Lebanon 138kV transmission line, and a new 125' tall microwave tower and associated Telecom facilities. The new network interconnection facility will be a three (3) breaker ring bus arrangement with three (3) 138kV lines (Lebanon, Brown Plant/Danville North, & Generator Interconnect).

The OATT allows two payment options for required Network Facilities:

1. LG&E/KU may pay for these Network Upgrades itself and include them in rates upon the equipment being placed in service, while requiring the Customer to provide appropriate security (letter of credit or parent guarantee), or
2. LG&E/KU may require the Customer to front the costs of Network Upgrades, and then pay back these costs, plus interest based on the prime rate, to the Customer after the solar facility is in service, and *then* include the costs in rates at the point in which equipment is paid for in full.

It is recommended that LG&E/KU go with the first option because funding can be secured at a lower interest rate than the prime rate.

Station
[redacted]

<u>Why is the project needed? What if we do nothing?</u>
LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in Marion County, KY and interconnect with LG&E/KU's Brown Plant to Lebanon 138kV line. See Figure 1 immediately below. This project will have minimal impact on reliability and/or the customer experience.

<u>Figure 1</u>

[redacted]

<u>Contract Bid Summary</u>
Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreement with the Customer in November 2020. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement it is executed). The project is estimated to take approximately twenty-four months from the customer's written notice to proceed and provision of security until construction is complete and the unit achieves commercial operation status.

Contract Financial Summary

Contract expenses ($k)	2020	2021	2022	2023	2024	Post 2024	Total
Amount requested based on contract award estimates	-	51	2,526	6,381	-	-	8,958
Contingency Amount Requested	-	-	-	896	-	-	896
Total contract authority requested	-	51	2,526	7,277	-	-	9,854
Interconnection Reimbursement	-	-	-	(1,030)	-	-	(1,030)
Net contract	-	51	2,526	6,247	-	-	8,824

This project is currently not included in any Business Plan. The customer has the right to suspend for up to three years. If the customer elects to proceed with the project, we will seek funding within Transmission or through the RAC.

The projects contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	51	2,526	7,277	9,854
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	51	2,526	7,277	9,854
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(51)	(2,526)	(7,277)	(9,854)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(51)	(2,526)	(7,277)	(9,854)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($'000s)	163635 Subs Interconnection Facilities (100% Reimbursable)	163640 Subs Network Facilities	163641 Lines Network Facilities	Total
Company Labor	42	499	-	541
Contract Labor	286	2,782	700	3,768
Materials	446	2,409	291	3,146
Contingency	94	689	113	896
Burdens	162	1,201	140	1,503
Gross Capital Expenditures	1,030	7,580	1,244	9,854
Reimbursement	(1,030)	-	-	(1,030)
Net Capital Expenditures	-	7,580	1,244	8,824
Contingency	10%	10%	10%	10%

Risks

- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost;

however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.

- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Facilities. If the commercial operation date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted], has granted service. To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed consistent with Companies' interconnection guidelines and similarly to the previously approved projects and executed LGIAs [redacted].

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] project for $9,854k as well as the Large Generator Interconnection Agreement – [redacted] for $9,854k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Large Generator Interconnection Agreement contract for $9,854k [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Beth McFarland	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.
Appendix A

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Appendix B

Figure 3

Conceptual Substation Layout

[redacted]

Figure 4

Project location map

CONFIDENTIAL INFORMATION REDACTED

Case No. 2020-00350

[redacted]

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: Crab Orchard Tap Conductor Replacement

Total Capital Expenditures: $4,288k (Including $406k of contingency and $145k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160059 – Lines Construction ($4,110k)
LI-163809 – Lines ROW ($178k)

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Brief Description of Project

The proposed project is to replace 2.81 miles of overhead transmission line and conductor that is over 50+ years old and beyond its expected useful life. Kentucky Utilities Crab Orchard substation serves over 604 customers with 3.14 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to Crab Orchard area.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 2.81 miles of 2/0 aluminum conductor steel reinforced (ACSR) conductor in the Crab Orchard 775 69kV tap with 397 ACSR 26/7. In addition, thirty-eight (38) wood and steel structures will be replaced with twenty-four (24) new steel structures. Structure spotting considerations resulted in the elimination of fourteen (14) existing structures. Due to the limitations of obtaining an extended outage, a portable substation will be utilized to limit customer impact, and a new line will be constructed parallel to the existing line, while the existing line remains energized. Right of way will be acquired on project LI-163809 to expand the existing right of way corridor to support completion of this project.

Project Milestones – Transmission Lines	
June 2020-September 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer

November 2020	Steel Poles Ordered
February 2021	Steel Poles Received
March 2021	Line Construction Begins
June 2022	Line Construction Completed

<u>Why is the project needed? What if we do nothing?</u>

The existing 2.81 miles of 69kV line in the Crab Orchard 775 tap contains the original 2/0 ACSR conductor installed in 1962. Non-destructive testing was performed on the conductor in 2018 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting.

In July of 2020, the transmission project was opened for $553k to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of nineteen (19) tangent steel H-frame structures, one (1) single pole angle structure, two (2) steel single pole dead end structures, one (1) self-supporting single steel dead end structure, and one (1) steel self-supporting switch structure.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	489	2,540	733	-	3,762
2. Cost of Removal Proposed	-	158	367	-	526
3. Total Capital and Removal Proposed (1+2)	489	2,698	1,101	-	4,288
4. Capital Investment 2021 BP	308	2,540	861	-	3,709
5. Cost of Removal 2021 BP	-	158	426	-	585
6. Total Capital and Removal 2021 BP (4+5)	308	2,698	1,287	-	4,294
7. Capital Investment variance to BP (4-1)	(180)	(0)	128	-	(53)
8. Cost of Removal variance to BP (5-2)	-	-	59	-	59
9. Total Capital and Removal variance to BP (6-3)	(180)	(0)	187	-	6

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects in the 2020 9+3 Forecast.

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- A portable substation will be utilized to minimize customer impact during construction.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 5,261
   The recommendation is to replace 2.81 miles containing 2/0 conductor with new 397 ACSR 26/7 conductor and replace thirty-eight (38) existing wood and steel structures with twenty-four (24) new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 6,896
   The Next Best Alternative would be to construct a new 3.0 mile transmission line. Constructing a new route would require the purchase of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Crab Orchard Conductor Replacement project for $4,288k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: PR Harlan Y Proactive Control House Replacement

Total Capital Expenditures: $4,122k (Including $374k of contingency including $183k of internal labor)

Total O&M: $ 0k

Project Number(s): SU-000130

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

<u>Brief Description of Project</u>

As part of the Transmission System Improvement Plan (TSIP), this project is a combination of several system integrity programs to address assets in need of replacement at Harlan Y substation. Harlan Y has assets operating at 161kV and 69kV that have been in service for longer than 50 years. The substation serves as a hub for the Harlan area and contains many Distribution circuits. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events. High-speed relaying will be implemented on three of the four 161kV lines via digital communication schemes over the Telecom network further increasing reliability. Additionally, Harlan Y substation is adjacent to Martin's Fork; one of two rivers that make up the Cumberland River. Due to the floodplain of this river, the new control house will be constructed atop piers that will raise the floor level above the 100-year floodplain. The existing 69kV control house currently subsides within the 100-year floodplain while the existing 161kV substation is elevated above the floodplain. The existing 69kV and 161kV control houses will be demolished once the new control house is in service.
- Replace Substation Breakers - Two (2) 69kV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – One (1) 69kV 3-phase high voltage disconnect switch will be replaced. This switch is supported by cap & pin insulators which are targeted for replacement due to a high risk of failure. A high-side Potential Transformer disconnect will also be removed as this equipment is a common point of failure, resulting in an increased risk of bus outages.

- Replace Substation Line Arresters – Two (2) 69kV sets of line surge arresters. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Fence – Due to aged conditions of the fence, and the need to expand the fence around the location of the new control house, this project will include a full replacement of the fence with approximately 1200 feet of 7-foot tall chain-link fencing per substation standards.

Due to the FERC 7 factor test, a 69kV breaker and the associated relay panel will be transferred to Distribution. A separate project number and AIP for these assets will be provided at full approval.

[redacted]

Why is the project needed? What if we do nothing?
The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are 50+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1	770	1,823	1,473	-	4,066
2. Cost of Removal Proposed	-	-	-	55	-	55
3. Total Capital and Removal Proposed (1+2)	1	770	1,823	1,528	-	4,122
4. Capital Investment 2021 BP	1	525	2,068	1,524	-	4,117
5. Cost of Removal 2021 BP	-	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	1	525	2,068	1,524	-	4,117
7. Capital Investment variance to BP (4-1)	-	(245)	245	51	-	51
8. Cost of Removal variance to BP (5-2)	-	-	-	(55)	-	(55)
9. Total Capital and Removal variance to BP (6-3)	-	(245)	245	(5)	-	(4)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-	-

Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects in the 2020 9+3 Forecast. The higher spend in 2022 will be funded by a reduction in other Transmission capital projects during the 2022 BP.

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This project will remove three 69kV line panels currently utilizing GCX relays.
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,183

2. Alternative #1: NPVRR: ($000s) 4,270
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PR Harlan Y Control House project for $4,122k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix

Exhibit A: Harlan Y Scope Outline

[redacted]

Exhibit B: Harlan Y Substation Overview

[redacted]

Exhibit C: FEMA Floodplain Map

[redacted]

Exhibit D: Major Replaced Equipment Age

Equipment	Install Date
161kV Control House	1956
69kV Control House	Unknown per Cascade data. At least 1961
Oil Circuit Breaker 618	1961
Oil Circuit Breaker 624	1965

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: TEP-Maximum Operating Temperature-Elizabethtown-Elizabethtown 5

Total Capital Expenditures: $2,082k (Including $189k of contingency and $78k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines - LI-159248 ($1,868k)
Distribution Operations – 163596 ($214k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Elizabethtown - Elizabethtown 5 69kV line overloads in Transmission Expansion Plan (TEP) studies. This project is required by the Companies' Transmission Planning Guidelines and was approved by [redacted], the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak, and base case conditions (without a generator or transmission outage) the Elizabethtown - Elizabethtown 5 69kV line overloads to 101.8% of normal rating in 2021. The overload is 109.6% in 2029. The Companies' Transmission Planning Guidelines require a project when the overload exceeds 100% of the normal rating through the end of the ten year planning horizon.

When the Maximum Operating Temperature upgrade (MOT) project is completed, the summer normal rating will go from 49 MVA to 52 MVA thus resolving the overload issue.

This project was opened for preliminary services in August of 2020 for $87k for engineering services to further develop the project scope and estimate to support this large capital project.

In order to increase the line MOT, (30) structures/poles will require replacement to maintain required clearance. Specifically, this project involves the replacement of twenty-five (25) existing wood structures with new steel structures, and five (5) existing wood stub poles with five (5) new steel sub poles. This work also involves working within state/county road right of way and on railroad property.

Project Milestones – Transmission Lines	
August 2020-September 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
November 2020	Steel Poles Ordered
March 2021	Steel Poles Received

April 2021	Line Construction Begins
September 2021	Line Construction Completed

Electric Distribution Operations will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
July 2020-September 2020	Engineering and Design
November 2020	Materials Ordered
March 2021	Materials Delivered
April 2021	Construction Start
September 2021	Construction Completed

<u>Project Cost</u>

	Transmission Lines	Distribution Operations	Total
Total 2020	$87k	$0	$87k
Total 2021	$1,781k	$214k	$1,995
Project Total	$1,868k	$214k	$2,082
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>
The overload of the Elizabethtown - Elizabethtown 5 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, it will be in violation of the Company's Transmission Planning Guidelines and put customer load at risk.

[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	87	1,669	-	-	1,757
2. Cost of Removal Proposed	-	325	-	-	325
3. Total Capital and Removal Proposed (1+2)	87	1,995	-	-	2,082
4. Capital Investment 2021 BP	87	2,270	-	-	2,357
5. Cost of Removal 2021 BP	-	254	-	-	254
6. Total Capital and Removal 2021 BP (4+5)	87	2,524	-	-	2,611
7. Capital Investment variance to BP (4-1)	-	601	-	-	601
8. Cost of Removal variance to BP (5-2)	-	(71)	-	-	(71)
9. Total Capital and Removal variance to BP (6-3)	-	529	-	-	529

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Without the recommended MOT upgrade of the Elizabethtown - Elizabethtown 5 69kV line, the Company will be in violation of the its Transmission Planning Guidelines and the TEP process. Not completing this project also places customer load at risk of interruption.

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,525
   The recommendation is to replace twenty five (25) existing wood structures with new steel structures, and five (5) existing wood stub poles with five (5) new steel stub poles.
2. Alternative #1: NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 4,206
   Build a new 69kV line from the KU Elizabethtown 69kV substation to the Elizabethtown 5 69 kV substation, approximately 3 miles. This project would require purchase of a new, or expansion of existing 69kV ROW, all new 69kV structures, and 556.5 MCM 26X7 ACSR conductor or an equivalent. Expansion of both the Elizabethtown and Elizabethtown (5) 69kV substations to accommodate the additional 69 kV line exits, breakers and all other associated terminal equipment would also be necessary.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TEP-MOT-Elizabethtown-Elizabethtown 5 project for $2,082k to comply with the Company's' Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment and Contract Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: [redacted] Solar Generator Interconnection Agreement and Project
Contract Name (Good/Service): Large Generator Interconnection Agreement – [redacted]

Selected Vendor(s): Not Applicable

Contract Authorization Requested: $ 10,966k (Including $997k of contingency)

Contract Term:

Total Capital Expenditures Requested: $ 10,966k (gross), $9,955k (net) (Including $997k of contingency and $562k of internal labor)
Total O&M: $0k

Project Number(s): 163672 Interconnection Subs, 163673 Network Facilities Subs, and 163674 Network Facilities Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted]

On February 6, 2019 [redacted] (customer) proposed the interconnection of a new 104MW solar generating facility in [redacted]. [redacted] and LG&E/KU have performed all necessary studies related to this request and TranServ has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Facilities that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $10,966k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $1,011k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $9,955k.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $10,966k, which includes a 10% contingency. This contingency covers increases in actual costs beyond the estimate. This work is not included in the 2021 BP becasue the customer indicated they would suspend the agreement upon execution of the LGIA which delays performing the work for up to three years. Funding will be included in future BPs when greater certainty exists that the project will be constructed. [redacted] retains the option to terminate the LGIA; however, the customer must provide acceptable security to ensure LG&E/KU is reimbursed for incurred construction costs if the generation interconnection does not become operational.

Interconnection Facilities
The new interconnection facility will be constructed adjacent to the Interconnection Customer's (IC's) generation facility. The interconnection facilities include 161kV structures and equipment necessary to terminate the generator lead line and to provide metering. The IC will be responsible for the design, construction, and permitting of the 161kV transmission line from their facilities to the Point of Change of Ownership (PCO) at the [redacted] Solar Station. [redacted]

The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities upon completion of the project.

Network Facilities
The network facilities include a new 161kV interconnection station, a 161kV loop connection to the existing Grahamville to Wickcliffe 161kV transmission line, and a new 195' tall microwave tower and associated Telecom facilities. The new network interconnection facility will be a three (3) breaker ring bus arrangement with three (3) 161kV lines (Grahamville, Wickcliffe, & Generator Interconnect)

The OATT allows two payment options for required Network Facilities:

1. LG&E/KU may pay for these Network Upgrades itself and include them in rates upon the equipment being placed in service, while requiring the Customer to provide appropriate security (letter of credit or parent guarantee), or
2. LG&E/KU may require the Customer to front the costs of Network Upgrades, and then pay back these costs, plus interest based on the prime rate, to the Customer after the solar facility is in service, and *then* include the costs in rates at the point in which equipment is paid for in full.

It is recommended that LG&E/KU go with the first option because funding can be secured at a lower interest rate than the prime rate.

Station
[redacted]

Why is the project needed? What if we do nothing?

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will [redacted] and interconnect with LG&E/KU's Grahamville to Wickcliffe 161kV line. See Figure 1 immediately below. This project will have minimal impact on reliability and/or the customer experience.

Figure 1

[redacted]

Contract Bid Summary

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreement with the Customer in Novermber 2020. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement it is executed). The project is estimated to take approximately twenty-four months from the customer's written notice to proceed and provision of security until construction is complete and the unit achieves commercial operation status.

Contract Financial Summary

Contract expenses ($k)	2020	2021	2022	2023	2024	Post 2024	Total
Amount requested based on contract award estimates	-	219	7,518	2,232	-	-	9,969
Contingency Amount Requested	-	-	-	997	-	-	997
Total contract authority requested	-	219	7,518	3,229	-	-	10,966
Interconnection Reimbursement	-	-	-	(1,011)	-	-	(1,011)
Net contract	-	219	7,518	2,218			9,955

This project is currently not included in any Business Plan. The customer has the right to suspend for up to three years. If the customer elects to proceed with the project, we will seek funding within Transmission or through the RAC.

The projects contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	219	7,518	3,229	10,966
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	219	7,518	3,229	10,966
4. Capital Investment 2021 BP	-	-	-	-	-
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(219)	(7,518)	(3,229)	(10,966)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(219)	(7,518)	(3,229)	(10,966)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($'000s)	163672 Subs Interconnection Facilities (100% Reimbursable)	163673 Subs Network Facilities	163674 Lines Network Facilities	Total
Company Labor	27	535	-	562
Contract Labor	265	2,690	996	3,951
Materials	472	2,836	467	3,775
Contingency	92	738	167	997
Burdens	155	1,315	211	1,681
Gross Capital Expenditures	1,011	8,114	1,841	10,966
Reimbursement	(1,011)	-	-	(1,011)
Net Capital Expenditures	-	8,114	1,841	9,955
Contingency	10%	10%	10%	10%

Risks

- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.

- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Facilities. If the commercial operation date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed consistent with Companies' interconnection guidelines and similarly to the previously approved projects and executed LGIAs with [redacted]

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the [redacted] Solar project for $10,966k as well as the Large Generator Interconnection Agreement – [redacted] for $10,966k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Solar Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Large Generator Interconnection Agreement contract for $10,966k with [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Beth McFarland	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Appendix A

[redacted]

Appendix B

[redacted]

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Dorchester-Arnold Pole Replacement

Total Capital Expenditures: $3,938k (Including $352k of contingency and $125k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-158882

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-three (33) existing wood structures with steel on the Dorchester-Arnold 161kV line during a scheduled outage. The scope of work includes the replacement of thirty-three (33) structures identified through inspection in 2018.

Of the thirty-three (33) structures being replaced, six (6) are in Kentucky and twenty-seven (27) are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for the section of line located in Virginia. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $494k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
January 2021	Steel Poles Received
February 2021	Line Construction Begins
July 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine inspection of the Dorchester-Arnold 161kV line was completed in 2018 and thirty-three

(33) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing thirty (30) steel H-frame structures, and three (3) steel 3-pole angle structures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	28	25	3,309	-	3,361
2. Cost of Removal Proposed	-	-	577	-	577
3. Total Capital and Removal Proposed (1+2)	28	25	3,886	-	3,938
4. Capital Investment 2021 BP	28	25	3,309	-	3,361
5. Cost of Removal 2021 BP	-	-	577	-	577
6. Total Capital and Removal 2021 BP (4+5)	28	25	3,886	-	3,938
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Dorchester-Arnold 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,469
   The recommendation is to replace thirty-three (33) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 6,836
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 4,675
   The next best alternative would be to replace all thirty-three (33) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester-Arnold pole replacement project for $3,938k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Dorchester-Pocket North Pole Replacement

Total Capital Expenditures: $10,672k (Including $970k of contingency and $249k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-158883

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace eighty-nine (89) existing wood structures with steel on the Dorchester-Pocket North 161kV line during a scheduled outage. The scope of work includes the replacement of eighty-five (85) structures identified through inspection in 2018. In addition, four (4) adjacent structures will be replaced in order to accommodate the height of the new structures.

All eighty-nine (89) structures being replaced are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for this project. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $698k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
June 2021	Steel Poles Received
October 2021	Line Construction Begins
October 2022	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine inspection of the Dorchester-Pocket North 161kV line was completed in 2018, and eighty-five (85) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, four (4) structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing sixty-nine (69) standard steel H-frame structures, five (5) steel tangent H-frame structures, six (6) steel three pole guyed running angle structures, six (6) steel dead end H-frame structures, and three (3) steel light angle H-frame structures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	5	588	4,356	4,136	9,085
2. Cost of Removal Proposed	-	-	569	1,019	1,588
3. Total Capital and Removal Proposed (1+2)	5	588	4,925	5,155	10,672
4. Capital Investment 2021 BP	5	588	4,357	4,589	9,538
5. Cost of Removal 2021 BP	-	-	569	1,019	1,588
6. Total Capital and Removal 2021 BP (4+5)	5	588	4,926	5,608	11,126
7. Capital Investment variance to BP (4-1)	-	0	1	453	454
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	0	1	453	454

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Dorchester-Pocket North 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 11,881
   The recommendation is to replace eighty-nine (89) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 17,364
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 12,251
   The next best alternative would be to replace all eighty-nine (89) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester-Pocket North pole replacement project for $10,672 to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Harlan Y-Pocket North Pole Replacement

Total Capital Expenditures: $2,360k (Including $215k of contingency and $91k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160075

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nick Poston/Adam Smith

Brief Description of Project

The proposed project is to replace twelve (12) existing wood structures with steel on the Harlan Y-Pocket North 161kV line during a scheduled outage. The scope of work includes the replacement of twelve (12) structures identified through inspection in 2018.

Of the twelve (12) structures being replaced, seven (7) are in Kentucky, and five (5) are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for the section of line in Virginia. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $386k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered
May 2021	Steel Poles Received
August 2021	Line Construction Begins
September 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine inspection of the Harlan Y-Pocket North 161kV line was completed in 2018, and twelve (12) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing seven (7) steel H-frame structures, three (3) steel 3-pole dead end structures, and two (2) steel 3-pole running corners.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	67	1,967	-	2,033
2. Cost of Removal Proposed	-	-	327	-	327
3. Total Capital and Removal Proposed (1+2)	-	67	2,294	-	2,360
4. Capital Investment 2021 BP	-	67	1,967	-	2,033
5. Cost of Removal 2021 BP	-	-	327	-	327
6. Total Capital and Removal 2021 BP (4+5)	-	67	2,294	-	2,360
7. Capital Investment variance to BP (4-1)	-	(0)	-	-	(0)
8. Cost of Removal variance to BP (5-2)	-	-	0	-	0
9. Total Capital and Removal variance to BP (6-3)	-	(0)	0	-	(0)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Risks

Without the proposed replacement of the priority poles on the Harlan Y-Pocket North 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,859

   The recommendation is to replace twelve (12) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 4,371
   The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: NPVRR: ($000s) 3,896
   The next best alternative would be to replace all twelve (12) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Harlan Y-Pocket North pole replacement project for $2,360k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: KU Park-Bimble-London Right of Way

Total Capital Expenditures: $746k (Including $68k of contingency and $26k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162349

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Paul Weis

Brief Description of Project

Transmission Lines seeks funding authority of $746k to acquire the permanent easement rights of way for the existing KU Park-Bimble 69kV transmission circuit and a portion of the Bimble-London 69kV transmission circuit.

In 1923, the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the KU Park-Bimble circuit and a portion of the Bimble-London circuit located to the northwest of the Bimble substation. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a legal concern at that time regarding the rule against perpetuity that does not currently exist in case law. This project will acquire permanent easement ROW in Knox County for the existing KU Park-Bimble-London 69kV circuits. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate these transmission lines and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements begin to expire in 2022 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $110k for title research and land evaluation services in May of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019 on a near-by transmission line, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research of all the transmission lines originating from the Pineville transmission station (KU Park). Portions of the KU Park-Bimble-London lines were determined to be covered under separate 99-year leases for access and use rights. At various times in the 1920's, 1963 and 1974 permanent easements were secured for portions of these circuits. The current lease agreements, which cover 47 parcels with 43 different landowners over 3.25 line miles, will begin to expire in Q3 2022. At that time the

Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities. Prescriptive rights are not applicable due to the current active 99-year term of the agreements.

At this time no additional transmission lines originating from the Pineville area or extending north to the E.W. Brown plant have been determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	61	464	222	-	746
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	61	464	222	-	746
4. Capital Investment 2021 BP	99	1,020	453	-	1,573
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	99	1,020	453	-	1,573
7. Capital Investment variance to BP (4-1)	39	556	232	-	826
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	39	556	232	-	826

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $4,500 per acre was utilized for easement cost estimates based upon the property valuation assessment completed as part of the Pineville – Rock Branch ROW project. Additionally, a 5% assumption was utilized to calculate the number of potential condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 1,116
   Secure the permanent easement ROW for the KU Park-Bimble-London 69kV circuits. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in the Company having to wait fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property where the circuit exists. This approach carries an

unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, area local officials and landowners are aware of this issue and there is local knowledge of this project with the initiation of the Pineville – Rocky Branch project. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: NPVRR: ($000s) 16,587
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option from that perspective either.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Bimble Right of Way project for $746k to support future line maintenance and construction along the KU Park-Bimble-London 69kV circuits.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Millersburg-Murphysville Conductor Replacement

Total Capital Expenditures: $27,498k (Including $2,500k of contingency and $977k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162670 – Transmission Lines Phase I
LI-162671 – Transmission Lines Phase II

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

The proposed project is to replace 25.2 miles of overhead transmission line conductor that is over 90+ years old and beyond its expected useful life. Kentucky Utility Sardis substation serves over 517 customers with 2.08 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Millersburg and Murphysville areas.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 25.2 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Millersburg-Murphysville EKPC 69kV line in two phases. The existing conductor will be replaced with 397 ACSR 26/7, and an optical ground wire (OPGW) will be installed. In addition, one hundred seventy-eight (178) wood structures will be replaced with one hundred sixty-seven (167) new steel structures. Structure spotting considerations resulted in the elimination of eleven (11) existing wood structures. Eight (8) existing steel structures will remain. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

This project will be completed in two phases:
Phase I – Murphysville-Sardis – 4.21 Miles
Phase II – Sardis-Millersburg – 20.98 Miles

Project Milestones – Transmission Lines	
April 2019-August 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
March 2021	Steel Poles Received
March 2021	Phase I Line Construction Begins
December 2021	Phase I Line Construction Completed
January 2022	Phase II Line Construction Begins
December 2023	Phase II Line Construction Completed

<u>Why is the project needed? What if we do nothing</u>

The existing 25.19 miles of 69kV line between Millersburg and Murphysville substations contains the original 3/0 ACSR conductor installed in 1928. Non-destructive testing was performed on the conductor in 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. This circuit has experienced a total of 39 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, weather, and equipment component failures.

In July of 2019, the transmission project was opened for $1,216k under project number 139958 to support preliminary engineering, project scope development, and site clearing. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of one hundred eight (108) standard steel H-frame structures, thirty-four (34) custom steel H-frame structures, five (5) self-supporting steel single pole dead end structures, one (1) self-supporting custom steel switch structures, fourteen (14) steel three pole dead end structures, four (4) steel single pole dead end structures, and one (1) steel Z-frame structure.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	808	226	11,461	14,038	26,533
2. Cost of Removal Proposed	19	-	161	785	964
3. Total Capital and Removal Proposed (1+2)	827	226	11,622	14,823	27,498
4. Capital Investment 2021 BP	808	948	11,460	12,039	25,255
5. Cost of Removal 2021 BP	19	13	371	3,685	4,087
6. Total Capital and Removal 2021 BP (4+5)	827	961	11,830	15,724	29,342
7. Capital Investment variance to BP (4-1)	-	722	(2)	(1,999)	(1,278)
8. Cost of Removal variance to BP (5-2)	-	13	210	2,900	3,123
9. Total Capital and Removal variance to BP (6-3)	-	735	208	901	1,844

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the 2021 Business Plan (BP) under project 139958.

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- An outage will be obtained so no customers will be out of service for the duration of the work.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 30,387
   The recommendation is to replace 25.19 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, one hundred seventy-eight (178) wood structures will be replaced with one hundred sixty seven (167) new steel structures.

2. Alternative #1: NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 59,477
   The Next Best Alternative would be to construct a new 27 mile transmission line which would parallel the existing line. Constructing a new route would require the purchase of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Millersburg-Murphysville Conductor Replacement project for $27,498k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Transmission Blankets - 2021

Total Expenditures: $4,700k

Project Number(s): Various

Business Unit/Line of Business: Transmission

Prepared/Presented By: Kyle Burns

Brief Description of Project

Transmission uses Blankets to budget and account for annual routine unidentified work. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. Transmission subdivides its Blankets into distinct categories for lines and substations. These categories align with primary work drivers for Transmission.
Annual blanket budgets are based on historical trends and operational input from the managers within Transmission. Blanket spend is monitored and forecast on a monthly basis based on known work identified throughout the year.

Transmission is requesting approval for $4,700k in blankets for 2021, a $613k increase from the 2020 Business Plan for 2021. This increase is due primarily to additional pole replacement funding in the blanket to help address the pole backlog, however this remains only 1.3% of the funding in the 2021 BP to address the pole backlog with most of the funding in specific pole replacement projects.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2021 Transmission blanket projects for $4,700k to help manage the Transmission work budgeted for 2021.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

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Transmission
2021 BP - Transmission Capital Blankets
$000s

[redacted]

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Walker Proactive Control House Replacement

Total Capital Expenditures: $3,323k (Including $302k of contingency including $89k of internal labor)
Total O&M: $ 0k

Project Number(s): SU-000325

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

A Transmission System Improvement Plan (TSIP) was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. As part of the TSIP, this project is a combination of several system integrity programs to address assets in need of replacement at Walker substation. Walker has assets operating at 161kV and 69kV that have been in service for longer than 50 years. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events. The lines exiting this station have had 87 Unknown events since 2012 with the Princeton to Walker double-circuit line having the 1st and 3rd worst Unknown rate on the Transmission system.
- Install Digital Fault Recorder (DFR) for improved system analysis and assistance with event cause coding. DFRs are also remotely accessible and can provide timely information to operating personnel as to the potential cause and location of the fault. Additionally, due to uncommon substation configuration, an additional relay panel will be installed at the nearby Earlington North Substation to improve protection of the 161kV line connecting the two stations. Currently, the 161/69kV transformer at Walker has no high-side breaker and its differential extends to Earlington North.
- Replace Substation Breaker – One (1) 69kV oil-filled circuit breaker will be removed and replaced with a modern SF6 insulated breaker. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers also reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – Two (2) 161kV 3-phase high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age

where failure is common, often during operation. Additionally, one (1) 69kV high-side Potential Transformer (PT) fused disconnect will be removed. This equipment is a common point of failure, resulting in an increased risk of bus outages.

- Replace Substation Line Arresters – Four (4) 69kV sets and one (1) 161kV set of line surge arresters will be replaced. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Insulators – Six (6) 3-phase cap and pin insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

[redacted]

Why is the project needed? What if we do nothing?

The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are 50+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	387	1,248	1,623	-	3,258
2. Cost of Removal Proposed	-	-	66	-	66
3. Total Capital and Removal Proposed (1+2)	387	1,248	1,688	-	3,323
4. Capital Investment 2020 BP	172	851	2,121	-	3,144
5. Cost of Removal 2020 BP	-	-	52	-	52
6. Total Capital and Removal 2020 BP (4+5)	172	851	2,173	-	3,196
7. Capital Investment variance to BP (4-1)	(215)	(397)	498	-	(114)
8. Cost of Removal variance to BP (5-2)	-	-	(14)	-	(14)
9. Total Capital and Removal variance to BP (6-3)	(215)	(397)	485	-	(127)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The unfunded capital in 2020 and 2021 will be funded through the reduction of other Transmission projects and coordinated through the Corporate RAC process.

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This project will remove three (3) 69kV line panels currently utilizing GCX relays.
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,540

2. Alternative #1: NPVRR: ($000s) 3,627
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PCH Walker project for $3,323k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Appendix

[redacted]

Exhibit B: Walker Substation Overview

[redacted]

[redacted]

Exhibit D: Major Replaced Equipment Age

Equipment	**Install Date**
Control House	1956
Oil Circuit Breaker 698	1966

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Clifty Creek 345kV Power Circuit Breaker Replacement

Total Capital Expenditures: $2,253k (Including $0k of contingency and $20k of internal labor)
Total O&M: $ 0k

Project Number(s): 152224

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

This project includes the replacement of (2) 345kV power circuit breakers within the Clifty Creek Substation which is owned and operated by Indiana-Kentucky Electric Corporation (IKEC), a subsidiary of OVEC. The project was originally approved for $1,306k in August 2018 and has been delayed and is now being revised to correspond with a recently updated and signed interconnection agreement between LKE and [redacted]. Per the interconnect agreement, the assets to be replaced are physically located and maintained in the state of Indiana by Indiana-Kentucky Electric Corporation (IKEC)-Clifty Creek personnel adding complexity to this project. Due to this circumstance, engineering and material costs escalated to conform with American Electric Power (AEP)/Ohio Valley Electric Corporation (OVEC) standards. Revised estimates are higher due to the following:

- The 2019 construction phase of this project was originally planned to coincide with the Clifty Creek - Trimble Co 345kV line reactor installation while employing [redacted] construction forces at a lower installed cost due to their familiarity with all tasks and risks involved in completion of this project. [redacted] elected to cease this construction path due to business reasons.
- The 2021 construction estimates, to perform this work, are exceedingly higher based on the selected LKE construction business partner's unfamiliarity with the location and the assumed risks. This location is also a designated CIP location and will require [redacted] supervision while on-site.
- This original recommendation remains as the best alternative for completing this work due to the cost increases in this estimate would also be incurred in the alternative estimate.

Why is the project needed? What if we do nothing?

The (2) 345kV breakers that are being targeted for replacement are part of a program to replace aging and obsolete transmission assets. The replacement of these breakers will reduce the risk of a potential failure and improve reliability of the Transmission system. The two (2) aging 345kV breakers are air blast type circuit breaker vintage 1975. In addition to age, these breakers have a history of maintenance issues and spare parts are limited. Asset Management has identified these two breakers as overdue for replacement. The replacement of these breakers will reduce risk of a potential failure and improve the reliability of the Transmission system.

The two (2) 345kV breakers are LG&E assets, however they are located in the Clifty Creek substation which is owned and operated by Indiana-Kentucky Electric Corporation (IKEC). IKEC is responsible for operation of the DL and DL2 circuit breakers, therefore it is recommended that IKEC standard Siemens SPS2-362-63 SF6 type circuit breakers be purchased for this project.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,130	28	1,058	-	2,216
2. Cost of Removal Proposed	-	-	36	-	36
3. Total Capital and Removal Proposed (1+2)	1,130	28	1,095	-	2,253
4. Capital Investment 2021 BP	1,130	28	1,095	-	2,253
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	1,130	28	1,095	-	2,253
7. Capital Investment variance to BP (4-1)	0	-	36	-	36
8. Cost of Removal variance to BP (5-2)	-	-	(36)	-	(36)
9. Total Capital and Removal variance to BP (6-3)	0	-	-	-	0

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Completing the project involves risk related to high voltage substation construction work. Delaying this project exposes our system to the continuing risk of impacts from other potential transmission failures.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,349
   It is recommended that the breakers be replaced to reduce the potential risk to the Transmission system.
2. Alternative #1: NPVRR: ($000s) 2,538
   The next best alternative is to replace all of the identified equipment gradually over a period of several years instead of completing the numerous replacements in one time period. Intermittently completing the required work is not recommended as inherent risks will remain for extended durations. Additionally, this alternative will result in a loss of efficiency that comes with packaging similar work at one location.
3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as it puts Transmission at risk of not being able to accomplish targets established as part of the Transmission System Improvement Plan.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Clifty Creek 345kV Power Circuit Breaker Replacement project for $2,253k to enhance the reliability of the Transmission system.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Elihu-Wofford Conductor Replacement

Total Capital Expenditures: $37,907k (Including $3,446k of contingency and $1,471k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160440 – Transmission Lines Phase I
LI-160441 – Transmission Lines Phase II
LI-160442 – Transmission Lines Phase III

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

Electric Transmission requests approval to replace 32.9 miles of overhead transmission line conductor that is over 85 years old and beyond its expected useful life. Performance of this line has diminished with 29 interruptions since 2012, and major conductor failures occurring in 2012 and 2013. Non-destructive testing was performed on this conductor and revealed that it was in marginal to poor condition. In addition, this project will also replace one hundred forty-nine (149) defective wood structures. Out of approximately 470 transmission circuits, this line ranks in the top 15 overall in terms of event counts which are defined as any circuit interruption. This line serves two East Kentucky Power Cooperative (EKPC) substations, Mount Victory substation which serves 674 customers with 2.61 MVA of load and Cumberland Falls substation serving 1,974 customers with 13.88 MVA of load. This project will improve reliability, maintain network integrity and functionality, and reduce the risk of failures and unplanned transmission interruptions to the Somerset, Mt. Victory, and Williamsburg areas.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 32.9 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Elihu-Wofford 69kV line in three phases. The existing conductor will be replaced with 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, two hundred eighty-one (281) wood structures will be replaced with two hundred thirty-six (236) new steel structures. Structure spotting considerations resulted in the elimination of forty-five (45) existing wood structures. The work will be completed in three phases:

Phase I – Wofford-Cumberland Falls – 8.3 Miles
Phase II – Elihu-Mt. Victory – 10.9 Miles
Phase III – Cumberland Falls – Mt. Victory – 13.7 Miles

Project Milestones – Transmission Lines	
April 2018-August 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
January 2021	Steel Poles Received
April 2021	Phase I Line Construction Begins
December 2021	Phase I Line Construction Completed
January 2022	Phase II Line Construction Begins
December 2022	Phase II Line Construction Completed
January 2023	Phase III Line Construction Begins
March 2024	Phase III Line Construction Completed

Why is the project needed? What if we do nothing?

The existing 32.9 miles of 69kV line between the Elihu and Wofford substations contains the original 3/0 ACSR conductor installed in 1935. Non-destructive testing was performed on the conductor in 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. In addition, a routine inspection was completed in 2019, and one hundred forty-nine (149) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. This circuit has experienced a total of 29 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, conductor failures, trees falling into the line, and several unknown events, with the most recent event occurring in 2020.

In April of 2018, the transmission project was opened for $725k to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. This project was submitted for revision in July of 2019 for $1,958k to allow vegetation clearing to proceed, providing access to the right-of-way for environmental assessments, geotechnical assessments, surveying, and ultimately the future line construction. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of one hundred seventy-nine (179) standard steel H-frame structures, four (4) steel three pole running corners, sixteen (16) steel guyed dead end structures, thirty-five (35) custom steel H-frame structures, and two (2) custom steel self-supporting switch structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	777	900	7,908	26,458	36,043
2. Cost of Removal Proposed	-	-	171	1,693	1,864
3. Total Capital and Removal Proposed (1+2)	777	900	8,079	28,151	37,907
4. Capital Investment 2021 BP	777	900	7,800	24,333	33,810
5. Cost of Removal 2021 BP	-	-	406	4,956	5,362
6. Total Capital and Removal 2021 BP (4+5)	777	900	8,206	29,289	39,172
7. Capital Investment variance to BP (4-1)	-	-	(108)	(2,125)	(2,233)
8. Cost of Removal variance to BP (5-2)	-	-	234	3,264	3,498
9. Total Capital and Removal variance to BP (6-3)	-	-	126	1,139	1,265

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All interstate, highway, and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- An outage will be obtained so no customers will be out of service for the duration of the work.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 39,772
   The recommendation is to replace 32.9 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, two hundred eighty-one (281) wood structures will be replaced with two hundred thirty-six (236) new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: NPVRR: ($000s) 75,795
   The Next Best Alternative would be to construct a new 35 mile transmission line which would parallel the existing line. Constructing a new route would require the purchase of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Elihu-Wofford Conductor Replacement project for $37,907k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Mount Washington-Fairmount Pole Replacement

Total Capital Expenditures: $5,897k (Including $536k of contingency and $123k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161140

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred thirty-seven (137) existing wood structures on the Mount Washington EKPC-Watterson-Fairmount 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred eighteen (118) structures identified through a 2019 inspection. The replacement of nineteen (19) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
October-November 2020	Engineering and Design
November 2020	Space reserved for steel pole production with manufacturer
January 2021	Steel Poles Ordered
March 2021	Steel Poles Received
April 2021	Line Construction Begins
March 2022	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2019, and one hundred eighteen (118) structures (approximately 30% on those inspected) were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Nineteen (19) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost due to mobilization of crews back to the site each time one fails, and the probable overtime work involved in replacing each during an emergency. This alternative would also have a negative impact on transmission network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Of the structures being installed, there are one hundred twenty-six (126) steel single pole tangent structures, seven (7) steel single pole angle structures, three (3) steel single pole dead end structures, and one (1) steel three-pole dead end structure.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	3,089	1,957	-	5,046
2. Cost of Removal Proposed	-	331	520	-	851
3. Total Capital and Removal Proposed (1+2)	-	3,420	2,477	-	5,897
4. Capital Investment 2021 BP	-	3,104	1,678		4,783
5. Cost of Removal 2021 BP	-	331	216		547
6. Total Capital and Removal 2021 BP (4+5)	-	3,435	1,894	-	5,329
7. Capital Investment variance to BP (4-1)	-	15	(278)	-	(264)
8. Cost of Removal variance to BP (5-2)	-	-	(304)	-	(304)
9. Total Capital and Removal variance to BP (6-3)	-	15	(582)	-	(568)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Subsequent to the 2021 BP planning, nineteen (19) structures were identified to need replacement in order to accommodate the height of the new structures. Incremental funding in 2022 will be funded by a reduction in other Transmission capital projects.

Risks

Without the proposed replacement of the priority poles on the Mount Washington-Fairmount 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,470
   The recommendation is to replace one hundred thirty-seven (137) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 10,904
The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 8,687
The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) annually which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mount Washington-Fairmount Pole Replacement project for $5,897k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Substation IP Connectivity

Total Capital Expenditures: $2,147k (Including $159k of contingency and $32k of internal labor)

Total O&M: $ 712k

Project Number(s): SU-000383 IP Connectivity-KU Trans, SU-000497 IP Connectivity-LG&E Trans, SU-000498 IP Connectivity KU IT, and SU-000499 IP Connectivity LG&E IT

Business Unit/Line of Business: Transmission Substation

Prepared/Presented By: Syd Ulis/Brent Birchell

Brief Description of Project

Transmission Substations is proposing a technology development project to add Internet Protocol (IP) connectivity to six (6) electric substations (See Appendix A for the list of substations). This proposed project will compare two different technologies which will provide remote monitoring, access, and data acquisition to transmission substations and will enhance electronic safeguards necessary for IP connectivity. The information and intelligence obtained will be used to determine the long-term strategy towards establishing transmission substation IP connectivity in the normal course of business. The substations selected are classified as Low Critical Infrastructure Protection (CIP) Impact. The Low category only requires for inbound and outbound communications to the system to be monitored and controlled. Technologies proven during this technology development can be applied towards Medium CIP stations as IP connectivity is expanded. The lessons learned by evaluating multiple configurations across the six (6) substations will be incorporated into future engineering design practices. The security focus of this project will align with the company's cyber security strategy for Industrial Control System/Operational Technology (ICS-OT).

Over time, the nature of the equipment in electric substations has changed from electro-mechanical devices which have no data storage capabilities and no vulnerabilities other than physical attack, to current modern day devices which can store critical data and report that data back to central locations for analysis. These modern Intelligent Electronic Devices (IEDs) are electronic and have cyber security vulnerabilities associated with them because they utilize operating systems and firmware to control and perform the functions for which they are designed. Consequently, these Operational Technologies (OT) have many of the characteristics of Information Technologies (IT) such as passwords, configuration files, user accounts, data storage, and logs and require security efforts for critical infrastructure such as access monitoring and patching. Due to the characteristics and criticality of these devices to the transmission system, access must be protected both physically and electronically.

Electric substations that have an existing and established LG&E-KU telecommunication network will be the targeted sites for the initial roll out of IP connectivity in order to minimize network construction and compliance costs. Operationally, this allows for LG&E-KU Transmission to seek information and experience around the cost and benefits of IP connectivity at minimal practical cost.[redacted]

IP connectivity allows for Transmission to develop expertise in programs that offset O&M costs around security efforts such as locally changing passwords, retrieving logs, and gathering event data and configuration baselines. With IP connectivity, Transmission can automate maintenance activities such as password changes and configuration retrieval. Asset Management will use real time data to build and explore use cases that model trends of major equipment and proactively address trending issues prior to failure. Real time data will also be used by both the Planning and Reliability groups to select and prioritize projects that address problem areas within the Transmission System.

- Milestones:
  - December 2020 - Complete preliminary design work on six substations
  - January 2021 - Initialization of project resources
  - February 2021 - June 2021
    - Design and install substation equipment
    - Purchase network equipment
  - July 2021
    - Set up centralized system
    - Install network devices IED management system
    - Initialize maintenance agreements with software and equipment providers

Once this project is completed, baseline infrastructure will be in place for IP Connectivity to grow organically as projects are constructed.

<u>Why is the project needed? What if we do nothing?</u>
IP connectivity allows for remote access to a variety of substation IEDs. Remote access allows for real time troubleshooting and remote management of the devices that are critical to the reliability of the bulk electric system (BES). In addition to real time data access, the network infrastructure provides the capability to perform remote maintenance and investigations quickly and more efficiently due to eliminating drive time and reducing associated costs.

Substations are dependent on the physical security of the IEDs within the substation environment as there are currently no capabilities to deploy security best practices for electronic security. With IP connectivity, the substations can also be secured electronically. IP connectivity decreases the cost for security best practices for device monitoring through a Centralized Security Solution (CSS).

To obtain the full benefits of an IP network, the existing Supervisory Control and Data acquisition (SCADA) connection back to the Energy Mangement System (EMS) will utilize the same physical route of the remote access connection. These networks will be logically separated and secured.

Initiating an IP connectivity technology development project allows for LG&E-KU Transmission to begin to address security challenges associated with IEDs. The Transmission Substation Compliance/Automation group will develop expertise in administering secure remote access and

SCADA communications. This project will allow LG&E-KU to develop best practices for IP connecting all transmission substations outside of the test lab environment via a CSS.

- Future benefits from the project include:
  - Remote access which allows for real time troubleshooting/verification:
    - Rapid retrieval of settings which will cut down on engineering and technician travel time.
    - Automated retrieval of fault records, Sequence of Events (SOE), and oscillography.
    - Mass device configuration changes can be implemented faster and avoid recurrence of mis-operations.
    - Quicker outage restoration via fault location analysis and hence lower System Average Interruption Duration Index (SAIDI).
    - Phasor Measurement Units (PMU) deployment at LG&E-KU will improve understanding of the dynamic nature and performance of the grid, thus increasing model accuracy.
    - The ability to retrieve asset monitoring information for predictive maintenance.
  - Enhanced electronic security from the CSS:
    - Allow automatic authentication into IEDs and log device account access.
    - Provide secure remote engineering access, auto-login, command filtering.
    - Grant access to individual accounts, individual Microsoft® Active Directory accounts, or Active Directory groups.
    - Retrieve and store configuration files in a centralized database.
    - Maintain a history of configuration changes in an auditable database.
    - Remote password management.
    - Generate operation and compliance reports. All user operations are logged.
    - Publish logs to the Security Information and Event Management (SIEM) system for processing, monitoring, and storage.

Assumptions:

- If selected hardware solutions do not work at the intended locations, the hardware could be moved to other locations, but the labor cost to install at the initial location would be written-off to O&M, no O&M write-offs are assumed in this project.
- The engineering design will be assigned to one of the Transmission Engineering Procurement and Construction Management (EPCM) contractors and physical construction/commissioning will be done with internal labor.
- Sensitive work will be completed by Transmission Substation Compliance Automation. This will include:
  - CSS configuration
  - RTU configuration
  - RTU field support

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	2,104	-	-	2,104
2. Cost of Removal Proposed	-	43	-	-	43
3. Total Capital and Removal Proposed (1+2)	-	2,147	-	-	2,147
4. Capital Investment 2021 BP	-	1,902	-		1,902
5. Cost of Removal 2021 BP	-	43	-	-	43
6. Total Capital and Removal 2021 BP (4+5)	-	1,945	-	-	1,945
7. Capital Investment variance to BP (4-1)	-	(202)	-	-	(202)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(202)	-	-	(202)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	134	289	289	712
2. Project O&M 2021 BP	-	138	283	291	712
3. Total Project O&M variance to BP (2-1)	-	4	(6)	2	-

Incremental spend will be covered through other reductions within Transmission.

Risks

- Introduction of IP connectivity to the substation's control devices increases the threat vectors to the BES and non-BES systems. This risk is mitigated through implementation of planned security practices.
- Rapidly changing technology can increase equipment obsolescence and shorten equipment life cycles due to unsupported firmware.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,410
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A

   There are no other viable alternatives that would allow us to meet the strategic objectives and adhere to, or meet, the security and compliance requirements.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Substation IP Connectivity project for $2,147k to implement Internet Protocol (IP) connectivity to allow for remote management of substation devices to six (6) transmission substations that are critical to the reliability of the bulk electric system (BES).

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix A. Substation List[1]

Owner	Sub Name
LGE	Blue Lick
LGE	Canal
LGE	Middletown 138
KU	West Cliff
KU	West Shelby
KU	Viley Road

[1] Taken from "Substation IP Cost (12).xlsx" located at:
https://projects.sp.lgeenergy.int/sites/SubsIPConnect/default.aspx

[redacted]