Final Report

KY 49
2010 – 2014 Construction Work Plan

Clark Energy Cooperative, Inc.
Winchester, Kentucky

CLARK ENERGY
A Touchstone Energy Cooperative

January 2010

R·W·BECK
An SAIC Company

Final Report

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United States Department of Agriculture
Rural Economic and Community Development
Rural Utilities Service
Washington, DC 20250

January 26, 2010

2010-2014 Construction Workplan (CWP)

Paul Embs, President & CEO
Clark Energy Cooperative

I have completed my review of the cooperative's 2010-2014 CWP, which was prepared by R.W. Beck, and find it to be generally satisfactory for loan contract purposes. Approval to proceed with the proposed distribution system construction is contingent upon RUS's review and approval of an Environmental Report (reference 7 CFR 1794).

Headquarters, SCADA, and load management projects will be reviewed/approved by the Northern Regional Division office, as necessary. This action will be taken after their receipt of the CWP and other supporting documents (i.e., appropriate feasibility and engineering studies).

You should make a special effort to inform all of the cooperative's employees and contractors, involved in the construction of utility plant of any commitments made in the Environmental Report covering the construction of the facilities recommended in the CWP.

Changes (line improvements, tie lines, extensions, substations, etc.) in the CWP will require RUS approval. The environmental acceptability of any such changes shall also be established in accordance with 7 CFR 1794. The procedure for satisfying these environmental requirements shall be the same as that used in connection with this CWP approval.

It is your responsibility to determine whether or not loan funds and/or general funds are available for the proposed construction. If general funds are used, the requirements as outlined in 7 CFR 1717 need to be followed.

The construction shall be accomplished in accordance with RUS requirements. Specific reference should be made to 7 CFR 1726, Electric System Construction Policies and Procedures.

Mike Norman

Mike Norman
RUS Field Representative

USDA Rural Development

United States Department of Agriculture
Rural Development

MAR 3 2010

Mr. Paul G. Embs
President and CEO
Clark Energy Cooperative, Inc.
P.O. Box 748
Winchester, Kentucky 40392-0748

Dear Mr. Embs:

We have reviewed the Environmental Report (ER) covering the facilities recommended in Clark Energy Cooperative, Inc.'s (Clark Energy) 2010-2014 Construction Work Plan (CWP). In accordance with 7 CFR Part 1794, Environmental Policies and Procedures, as amended, all projects proposed in the CWP are Categorical Exclusions. No additional environmental information needs to be submitted for review, provided the projects do not change from what has been described in the ER.

Your CWP was approved by Mike Norman on January 26, 2010, contingent on approval of the ER. Clark Energy now has environmental clearance for all projects in the CWP and is responsible for acquiring the necessary permits for construction and operation of the proposed projects.

Thank you for your assistance and cooperation in helping us fulfill our environmental review requirements. If you have any questions, please contact me at (202) 720-1994 or Ms. Lauren McGee, Environmental Scientist, at or lauren.mcgee@wdc.usda.gov or (202) 720-1482.

Sincerely,

CHARLES M. PHILPOTT
Chief, Engineering Branch
Northern Regional Division
USDA Rural Utilities Service

CLARK ENERGY COOPERATIVE, INC.

RESOLUTION NO. 2010-

A RESOLUTION OF THE BOARD OF DIRECTORS OF CLARK ENERGY COOPERATIVE, INC. APPROVING A FOUR YEAR CONSTRUCTION WORK PLAN IN THE AMOUNT OF $18,061,857 FOR THE PERIOD JANUARY 1, 2010 TO DECEMBER 31, 2013 AS PREPARED BY TODD PEYTON, MANAGER OF ENGINEERING SERVICES AND R. W. BECK AND ASSOCIATES

WHEREAS, Todd Peyton, Manager of Engineering Services and R. W. Beck and Associates have prepared a four (4) year construction work plan for Clark Energy Cooperative, Inc. covering the period from January 1, 2010 to December 31, 2013; and

WHEREAS, the Board of Directors of Clark Energy Cooperative, Inc. having reviewed the work plan as prepared by Todd Peyton, Manager of Engineering Services and R. W. Beck and Associates and deems it in the best interest of the Cooperative to approve same,

NOW, THEREFORE, BE IT RESOLVED that the Board of Directors of Clark Energy Cooperative, Inc. that the four (4) year construction work plan presented to the Board of Directors of Clark Energy Cooperative, Inc. as prepared by Todd Peyton, Manager of Engineering Services and R. W. Beck and Associates in the amount of $18,061,857 for the period from January 1, 2010 to December 31, 2013, be, and the same is hereby approved as a plan of action to be followed until and unless amended with the approval of RUS.

Introduced upon motion made by Director Caudill,

seconded by Director Hollon, and passed by unanimous

vote of the Board of Directors of Clark Energy Cooperative, Inc.,

in duly session assembled, this 26th day of January, 2010.

William P. Shearer
CHAIRMAN OF THE BOARD

ATTEST:

O H Caudill
SECRETARY

January 22, 2010

R·W·BECK
An SAIC Company

Mr. Todd Peyton
Clark Energy Cooperative, Inc.
2640 Ironworks Road
PO Box 748
Winchester, KY 40391

Subject: **2010-2014 Construction Work Plan**

Dear Mr. Peyton:

We have completed our work in connection with the preparation of a 2010-2014 Construction Work Plan for Clark Energy Cooperative Inc. The Executive Summary summarizes the results of our studies and sets forth our conclusions and opinions. The data, information, and results of the analysis, which support our conclusions and opinions, are described in detail in subsequent sections of the Report.

We wish to acknowledge the cooperation and assistance received from the management and staff of Clark Energy Cooperative Inc. in the conduct of our studies and the preparation of the Report.

Sincerely,

R. W. BECK, INC.

Keith Mullen

Keith Mullen
Project Manager

PKM/mw

003884 | 07-70182-01363-1000

Clark Energy Cooperative, Inc.
Winchester, Kentucky
Kentucky 49, Clark

CONSTRUCTION WORK PLAN

I hereby certify that this 2010-2014 Construction Work Plan was prepared by me or under my direct supervision and that we are duly registered professional engineers under the laws of the State of Kentucky.

STATE OF KENTUCKY
PAUL KEITH
MULLEN, JR.
22948
LICENSED
PROFESSIONAL ENGINEER

PAUL KEITH MULLEN, JR.

Keith Mullen, P.E.
Project Manager

Date: 2010 - JAN - 22

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740C DETAIL

NEW CONSTRUCTION (Code 100)

Project Code	General Description	Miles	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
101	New Underground Lines	41.4	$439,875	$461,790	$482,512	$506,540	$1,890,717
102	New Overhead Lines	62.8	$775,382	$812,451	$848,880	$889,536	$3,326,249
100	**TOTAL NEW CONSTRUCTION**	104.2	$1,215,257	$1,274,241	$1,331,392	$1,396,076	**$5,216,966**

DISTRIBUTION LINE CONVERSIONS (Code 300)

RUS Code	General Description	Miles	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
378	**Clay City - Circuit 5 (New)**						
	Project Name - Virden Ridge-336						
	New construction three-phase 336 ACSR	0.34	$60,100				$60,100
	Reconductor and multi-phase to three-phase 336 ACSR	0.61	$81,700				$81,700
	Reconductor to three-phase 336 ACSR	0.05	$6,700				$6,700
	Switching and single-phase tap transfers	0.00	$0				$0
372	**Clay City - Circuit 2**						
	Project Name - Snow Creek-1/0						
	Multi-phase to three-phase 1/0 ACSR	1.53	$163,900				$163,900
	Single-phase tap transfers	0.00	$0				$0
379	**Clay City - Circuit 4**						
	Project Name - Highway 11-336						
	Reconductor and multi-phase to three-phase 336 ACSR	0.98			$140,600		$140,600
380	**Frenchburg - Circuit 3**						
	Project Name - Highway 36 @ Suiters Branch-336						
	Reconductor to three-phase 336 ACSR	1.38	$184,800				$184,800
	Single-phase tap transfers	0.00	$0				$0
373	**Hardwick's Creek - Circuit 1**						
	Project Name - Frames Branch-1/0						
	Multi-phase to three-phase 1/0 ACSR	1.61	$172,500				$172,500
	Single-phase tap transfers	0.00	$0				$0
374	**Hunt - Circuit 3**						
	Project Name - Drowning Creek-1/0						
	Reconductor and multi-phase to three-phase 1/0 ACSR	1.14	$122,100				$122,100
	Single-phase tap transfers	0.00	$0				$0
375	**Hunt - Circuit 3**						
	Project Name - Flint Rd.-1/0						
	Reconductor and multi-phase to three-phase 1/0 ACSR	0.66		$73,200			$73,200
	Single-phase tap transfers	0.00	$0				$0
381	**Mt. Sterling - Circuit 3**						
	Project Name - Goffs Corner-336						
	Reconductor and multi-phase to three-phase 336 ACSR	1.08		$149,700			$149,700
	Single-phase tap transfers	0.00		$0			$0
382	**Reid Village - Circuit 2**						
	Project Name - Prewitt Pike-336						
	Reconductor to three-phase 336 ACSR	0.66	$88,400				$88,400
	Single-phase tap transfers	0.00	$0				$0

740C DETAIL

DISTRIBUTION LINE CONVERSIONS (Code 300 - Continued)

RUS Code	General Description	Miles	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
367	**Stanton - Circuit 4**						
Carry-over	**Project Name - Lower Paint Creek**						
	Reconductor and multi-phase to three-phase 336 ACSR	0.61				$90,600	$90,600
	Single-phase tap transfers	0.00				$0	$0
383	**Van Meter - Circuit 3**						
	Project Name - Clintonville-336						
	Reconductor to three-phase 336 ACSR	2.48	$332,100				$332,100
377	**Stone Rd - Circuit 2**						
	Project Name - Stone Rd.-1/0						
	Reconductor and multi-phase to three-phase 1/0 ACSR	1.21	$129,800				$129,800
300	**TOTAL DISTRIBUTION LINE CHANGES**	14.34	$1,342,100	$222,900	$140,600	$90,600	**$1,796,200**

MISCELLANEOUS DISTRIBUTION ITEMS (Code 600)

RUS Code	General Description	Quantity	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
601	**METERS FOR NEW MEMBERS**						
	Underground	844	$31,257	$32,760	$34,344	$36,120	$134,481
	Overhead	1,290	$48,184	$50,397	$52,812	$55,432	$206,825
	COST OF METERS FOR NEW MEMBERS	2,134	$79,441	$83,157	$87,156	$91,552	**$341,306**
601	**METER REPLACEMENTS**						
	Underground & Overhead	4,000	$151,000	$156,000	$162,000	$168,000	$637,000
	COST OF METER REPLACEMENTS	4,000	$151,000	$156,000	$162,000	$168,000	**$637,000**
601	**TRANSFORMERS FOR NEW MEMBERS**						
	Padmounted	358	$163,944	$171,592	$179,640	$188,006	$703,182
	Overhead	762	$199,529	$208,656	$219,456	$229,502	$857,143
	COST OF TRANSFORMERS FOR NEW MEMBERS	1,120	$363,473	$380,248	$399,096	$417,508	**$1,560,325**
601	**AMR/AMI**		$40,200	$41,600	$43,000	$44,500	**$169,300**
	Upgrading to meters with built in remote disconnect devices						
601	**TOTAL TRANSFORMERS & METERS**		$634,114	$661,005	$691,252	$721,560	**$2,707,931**
602	**SERVICE UPGRADES FOR EXISTING MEMBERS**	302	$109,002	$114,300	$119,928	$125,741	**$468,971**

740C DETAIL

MISCELLANEOUS DISTRIBUTION ITEMS (Code 600 - Continued)

RUS Code	General Description	Quantity	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
603	**SECTIONALIZING EQUIPMENT**		$52,300	$53,700	$2,300	$13,100	**$121,400**
603-01	**Clay City - Circuit 1**						
	Replace switch with a gang switch		$6,400				$6,400
	Remove Recloser		$1,100				$1,100
603-02	**Clay City - Circuit 2**						
	Install (2) single-phase 70V4E reclosers		$11,800				$11,800
603-03	**Clay City - Circuit 4**						
	Relocate recloser				$2,300		$2,300
603-04	**Hardwick's Creek - Circuit 1**						
	Replace recloser with a 70V4E		$20,900				$20,900
	Relocate recloser						
	Install (2) single-phase 70V4E reclosers						
603-05	**Hunt - Circuit 3**						
	Replace recloser with (3) 50V4E		$12,100				$12,100
603-06	**Hunt - Circuit 3**						
	Install (2) single-phase 50V4E recloser			$12,200			$12,200
603-08	**Mt. Sterling - Circuit 3**						
	Replace recloser with three-phase VWVE#!			$41,500			$41,500
	Relocate (3) 50L's						
	Remove recloser						
603-15	**Stanton - Circuit 4**						
Carry-over	Install (2) single-phase 70V4E reclosers					$13,100	$13,100
604	**LINE REGULATORS**		$111,100	$0	$0	$0	**$111,100**
604-01	**Frenchburg - Circuit 3**						
	Relocate regulator RG.12		$4,700				$4,700
604-02	**Frenchburg - Circuit 1**						
	Relocate regulator RG.11		$4,700				$4,700
604-03	**Van Meter - Circuit 3**						
	Install (3) single-phase 219 A regulator		$49,900				$49,900
604-04	**High Rock - Circuit 1**						
	Install (1) single-phase 100 A regulator		$10,700				$10,700
604-05	**Reid Village - Circuit 1**						
	Install (3) single-phase 100 A regulators		$32,100				$32,100
604-06	**Stone Rd - Circuit 1**						
	Remove regulators RG.38 and REG13		$6,000				$6,000
604-07	**Clay City - Circuit 2**						
	Remove regulator RG.22		$3,000				$3,000

740C DETAIL

MISCELLANEOUS DISTRIBUTION ITEMS (Code 600 - Continued)

RUS Code	General Description	Quantity	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
606	**Pole Replacments**						
	Pole Replacements	1,587	$614,916	$699,736	$797,364	$906,815	**$3,018,831**
607	**Miscellaneous Replacements**						
			$72,300	$74,800	$77,500	$80,200	**$304,800**
608	**Conductor Replacement**						
	System-Wide	40.00	$235,700	$243,900	$252,500	$261,300	**$993,400**
611	**Hwy 801 - Clark Energy Hazard Mitigation Project**		$526,400	$0	$0	$0	**$526,400**
	Three phase overhead to three phase underground						
615-1	**Radio Communication**		$267,800	$277,200	$0	$0	**$545,000**
	Upgrading communictation equipment						
600	**TOTAL MISC. DISTRIBUTION ITEMS**		$2,623,632	$2,124,641	$1,940,844	$2,108,716	**$8,797,833**

RUS Code	General Description	Quantity	2010-2011	2011-2012	2012-2013	2013-2014	Estimated Cost
702	**SECURITY LIGHTS**	1,476	$112,176	$116,235	$120,294	$124,353	**$473,058**
704-2	**SCADA System**		$107,100	$110,900	$0	$0	**$218,000**
705-1	**AMR/AMI**		$370,100	$383,000	$396,400	$410,300	**$1,559,800**
	Upgrading all substations to two-way communications						
700	**TOTAL OTHER DISTRIBUTION ITEMS**		$589,376	$610,135	$516,694	$534,653	**$2,250,858**

TOTAL (740c)		**$5,770,365**	**$4,231,917**	**$3,929,530**	**$4,130,045**	**$18,061,857**

Purpose of Report

This 2010 - 2014 Construction Work Plan (CWP) documents the engineering analysis and proposed system improvements required for Clark Energy Cooperative, Inc. (Clark Energy) to provide satisfactory and reliable service to its customers through the winter peak of 2014. R. W. Beck (the Consultant) was retained to assist Clark Energy in the preparation of the CWP. Included within is engineering support for a loan application to RUS to finance the proposed construction program. The engineering support includes descriptions, estimated costs, and justification of required new facilities and facility improvements.

Service Area and Power Supply

Clark Energy provides service to approximately 26,170 customers located in all or parts of Clark, Montgomery, Bath, Menifee, Powell, Madison, Bourbon, Fayette, Rowan, Morgan, Wolfe, and Estill counties. Clark Energy purchases power at 24.9/14.4 kV or 12.5/7.2 kV from the East Kentucky Power Cooperative (EKPC). The 22 substations and transmission facilities serving Clark Energy are owned by EKPC. Union City and Three Forks substations are 138-kV delivery points, 20 of the remaining substations are 69-kV delivery points, and there are two meter points. Of the 22 substations, 16 substations have looped transmission service. The remaining six substations are served radially.

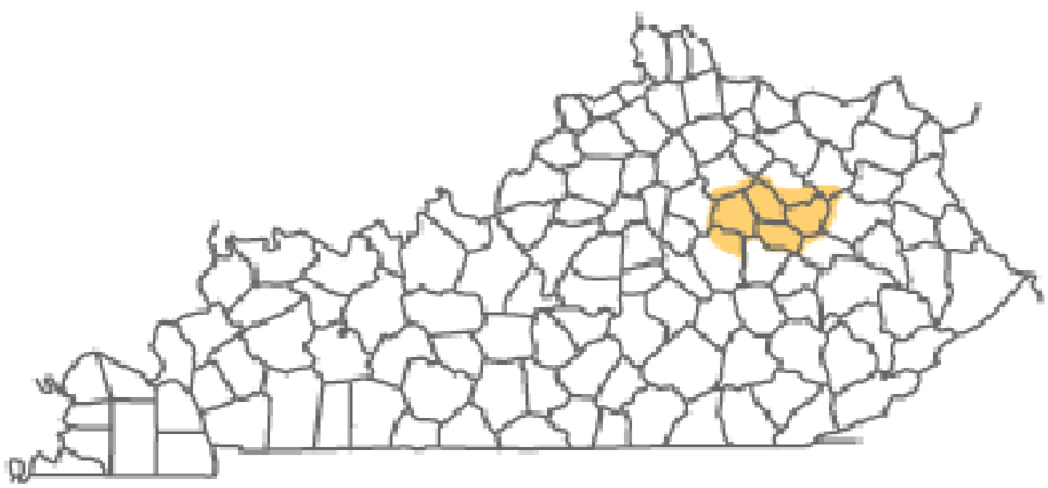

Figure ES-1: Location Map

From the 22 delivery EKPC and 2 meter points, Clark Energy distributes power at a primary voltage of 24.9/14.4 kV and 12.5/7.2 kV over approximately 3,014 miles of distribution lines via 72 distribution circuits. The installed overhead conductor sizes range from #6 CWC to 397 ACSR and total approximately 2,838 line-miles. Clark Energy also has approximately 176 miles of underground distribution lines. A tabulation of general operating statistics for the calendar years 2004 to 2008 from RUS Form 7 are shown in Table ES-1.

Table ES-1
General System Operating Statistics

	2004	2005	2006	2007	2008
Miles of Distribution Line	2,900	2,935	2,966	2,982	3,014
Year-End consumers per Month Served	25,030	25,386	25,694	25,963	26,170
Consumers per Mile	8.63	8.65	8.66	8.71	8.68
Average Residential Consumption (kWh/mo)	1,338	1,407	1,362	1,426	1,404
Total MWh Purchased	427,871	449,841	446,178	468,537	463,945
Total MWh Sold (1)	401,986	428,774	420,157	444,403	441,197
Percent System Losses	6.05%	4.68%	5.83%	5.15%	4.90%

Note:
Does not include own use.

Results of Proposed Construction

On completion of the proposed construction program, the system will adequately serve the 2013 summer peak load of 110.3 MW and the 2014 winter peak load of 143.9 MW as projected in the 2008 Load Forecast (LF) prepared by EKPC. The CWP was prepared to provide adequate and dependable service to 28,419 residential, commercial, and industrial customers with total annual sales of 510,338 MWh in 2014.

A detailed description of the proposed system improvements is given in Section 2. This CWP includes carryovers from the previous 2006 - 2010 CWP. The proposed system improvements are identified in the 740c Detail following the RUS 740c Form and are summarized in Table ES-2.

Table ES-2
System Improvements and Additions Summary

RUS Code	Item	Estimated Cost
100	New Construction	$5,216,966
200	New Tie Lines	$0
300	Line Conversions	$1,796,200
400	New Substations	$0
500	Substation Improvements	$0
600	Miscellaneous Distribution Equipment	$8,797,833
700	Other Distribution Equipment	$2,250,858
Total CWP Improvements		$18,061,857

General Basis of Study

The 2014 winter projected system peak load and number of customers served used in this report were based on the 2008 LF prepared by EKPC. Clark Energy’s load projections and recommendations were reviewed and generally found to be adequate for the CWP planning period. All of the construction proposed herein is consistent with the LF unless otherwise noted and explained. A copy of the 2008 EKPC LF is given in Appendix A of this report.

Clark Energy’s 2007 operations and maintenance review (Review Rating Summary, RUS Form 300) was used to determine construction required to replace physically deteriorated equipment and material, upgrade portions of the system to conform with code or safety requirements, and/or improve reliability or quality of service.

New distribution and power supply construction requirements were considered simultaneously as a “one system” approach for the orderly and economical development of the total system. All of the proposed construction and recommendations herein, relative to power supply and delivery, were discussed with the cooperative's power supplier, EKPC.

Details and estimated costs of the line and equipment changes and the additional requirements to serve 2,134 new residential, commercial, and industrial customers during the work plan period are included in Section 2. An estimated cost of necessary service upgrades to existing customers is also included in Section 2.

An analysis, using as a basis RUS guidelines and the design criteria herein, of thermal loading, voltages, physical conditions, and reliability, was performed on all of the substations, distribution lines, and major equipment of the existing system. Milsoft Integrated Solutions, Inc.’s WindMil™ software was used to analyze the distribution circuits for the projected 2013 summer peak load of 110.3 MW and the 2014 winter peak load of 143.9 MW. The economic conductor selection is given in Section 3. When applicable, alternate solutions were investigated and economically evaluated so the most cost effective construction could be proposed.

In the preparation of this Report, including the opinions contained herein, we have made certain assumptions and used certain considerations with respect to conditions which may occur in the future. While we believe these considerations and assumptions are reasonable and reasonably attainable based upon conditions known to us as of the date of this Report, they are dependent upon future events and actual conditions may differ from those assumed. In addition, we have used and relied upon certain information provided to us by others. To the extent actual future conditions differ from those assumed herein or from the assumptions provided by others, the actual results will vary from those estimated. In addition, field conditions encountered during design will impact some of the projects.

Section 1
BASIS OF STUDY AND PROPOSED CONSTRUCTION

1.1 Design Criteria

Construction proposed herein is required to meet the following minimum standards of adequacy for voltages, thermal loading, safety, and reliability on the system.

1. The maximum voltage drop on primary distribution lines is not to exceed 8 volts after regulation on a 120 volt base, including the effect of voltage re-regulation.

2. The following equipment is not to be thermally loaded by more than the percentage shown of its nameplate rating:
   - 100% Substation Transformer rating provided by EKPC
   - 80% Step Transformer rating
   - 80% Line Voltage Regulators
   - 80% Oil Circuit Reclosers
   - 80% Line Fuses

3. Primary conductors that are used as substation inter-ties will be reviewed if loaded near 50% of their calculated summer or winter rating. The remaining primary conductors will be reviewed at 80%.

4. Primary distribution lines will be reviewed for possible reconductor from single-phase to three-phase if loading exceeds 56 amps on single-phase lines to improve phase balance and conform with the existing coordination scheme.

5. Poles and/or crossarms will be reviewed if found to be physically deteriorated by visual inspection and/or tests. Clark Energy inspects poles and uses a contract crew to replace poles on a ten-year cycle.

6. Overhead conductors, associated poles, and hardware as required, will be replaced if conductor is old, in poor condition, and has excessive sag.

7. Primary distribution lines will be rebuilt and/or relocated if they are found to be unsafe or in violation of the National Electrical Safety Code or other applicable code clearances when originally constructed.

8. System improvements will be considered, and made if necessary, in specific areas where customers have experienced more than 200 outage minutes per year, excluding outages caused by major storms or the power supplier, for the last year.

9. New lines and line conversions will be built according to the standard primary voltage level of 24.9/14.4 kV.

10. New primary conductor sizes will be determined on a case-by-case basis using the economic conductor sizing and presently known constants and variables. The final proposed conductor may be modified to conform with the cooperative's standard sizes.

11. All new primary construction will be overhead except where underground is required to comply with governmental or environmental regulations, local restrictions, or favorable economics.

12. All new distribution lines will be designed and built according to RUS standard construction specifications and guidelines.

13. Recommendations to correct reactive demand to 90% power factor during peak summer loading will be evaluated.

1.2 Distribution Line and Equipment Costs

The distribution line and equipment costs are given in Tables 1-1 and 1-2. Clark Energy average costs from previous CWP were inflated 3.5% per year to represent 2009 dollars. The remaining costs were estimated based on utility averages. The estimated costs include engineering, overheads, and tree trimming for overhead lines. The 2009 estimated costs are inflated 3.5% per year until the year actual construction is performed.

Table 1-1
Distribution Line (Installed Cost)

Distribution Lines	2009 Estimated Cost ($/mile)
New Lines	
1ϕ; OH, #2 ACSR	$56,400
1ϕ; UG, #1/0 EPR	$180,000
1ϕ; OH, #1/0 ACSR	$65,000
1ϕ; OH, #4 ACSR	$48,000
3ϕ; OH, #2 ACSR	$92,600
3ϕ; OH, #1/0 ACSR	$100,000
3ϕ; OH, 336 kcmil ACSR	$125,000
3ϕ; OH, 795 kcmil ACSR	$190,000

Distribution Lines	2009 Estimated Cost ($/mile)
1ϕ to 1ϕ Line Reconductor	
With OH, #2 ACSR	$20,000
With OH, #1/0 ACSR	$22,000
1ϕ to 3ϕ Line Reconductor	
With OH, #2 ACSR	$92,600
With OH, #1/0 ACSR	$100,000
3ϕ to 3ϕ Line Reconductor	
With OH, #2 ACSR	$92,600
With OH, #1/0 ACSR	$100,000
With OH, 336 kcmil ACSR	$125,000
With OH, 336 Hendrix	$165,000
With OH, 795 kcmil ACSR	$190,000
7.2/12.5 kV to 14.4/24.9 kV Conversion	
1ϕ Conversion	$9,000
3ϕ Conversion	$15,000

Table 1-2
Distribution Equipment (Installed Cost)

Distribution Lines	2009 Estimated Cost
Line Regulators	
(1) 1ϕ, 100 Amp, 76.2 kVA	$10,000
(3) 1ϕ, 100 Amp, 76.2 kVA	$30,000
(3) 1ϕ, 219 Amp, 76.2 kVA	$46,600
Relocate (1) regulator bank	$4,400
Remove (1) regulator bank	$2,800
Autotransformer	
Auto – (1) 3ϕ 5 MVA	$190,440
Auto – (1) 3ϕ 7.5 MVA	$285,660
Auto – (1) 3ϕ 10 MVA	$368,000
Auto – (3) 1ϕ 333 kVA	$2,500
Relocate (1) Auto bank	$4,400
Remove (1) Auto bank	$2,800

Distribution Lines	2009 Estimated Cost
Recloser	
(1) 1ϕ recloser	$5,500
(3) 1ϕ recloser	$10,300
(1) 3ϕ recloser	$30,400
Relocate (1) recloser	$2,000
Remove (1) recloser	$1,000
Switch	
3-ph Overhead Gang Switch	$6,000

1.3 Status of Previous CWP Items

The previous work plan was prepared for the 2006-2010 construction period. Approximately 84% of the projects in this plan were completed, and 8% were cancelled based on amendments or the issues identified did not materialize. Approximately 8% of the 2006-2010 CWP projects will be designated as a carry-over for the 2010 – 2014 CWP. The status of each project is summarized in Exhibit 1 based on the following:

- Carry-Over Project will be a carry-over in the 2010 – 2014 CWP
- Complete Project has been completed
- Cancelled Project was cancelled.

1.4 Analysis of Current System Studies

1.4.1 2008 Load Forecast

EKPC prepared the 2008 Load Forecast (LF), which details the forecasted system coincident peak loads through 2027. Figure 1-1 illustrates the historical and projected winter peak demands from the 2008 EKPC LF. The 2008 EKPC LF was based on an average annual customer growth of 1.4%, and a growth of energy sales of 1.9%. A copy of the 2008 EKPC LF is attached in Appendix A.

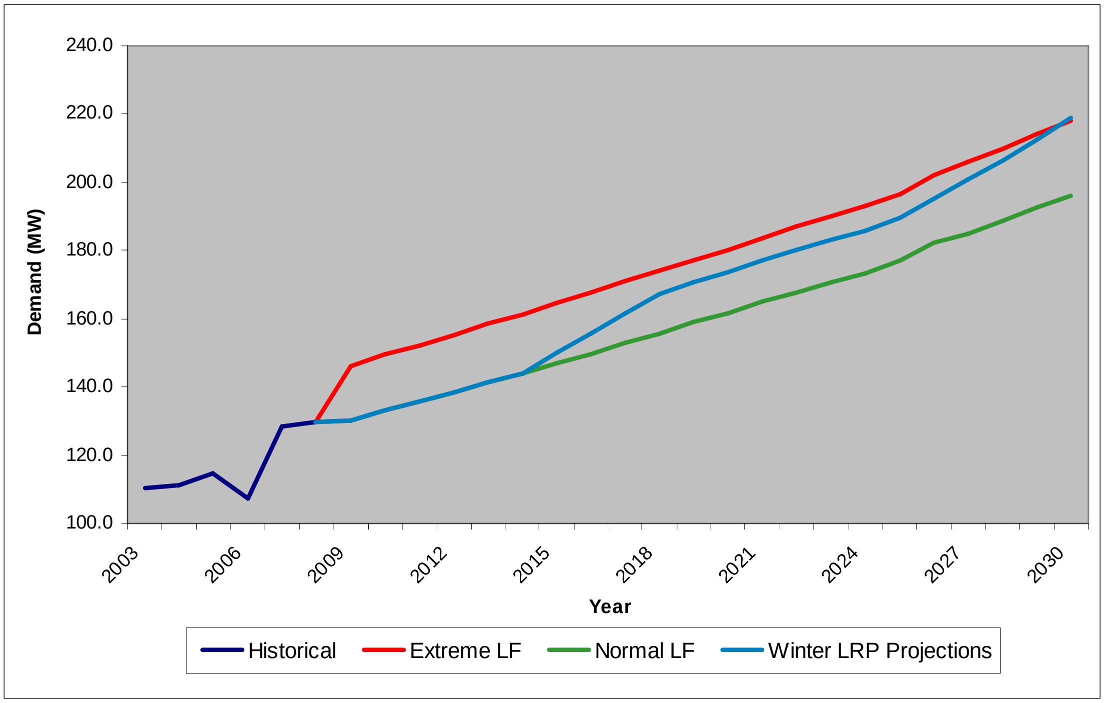

Figure 1-1 Winter Historical and Projected System Peak Demands

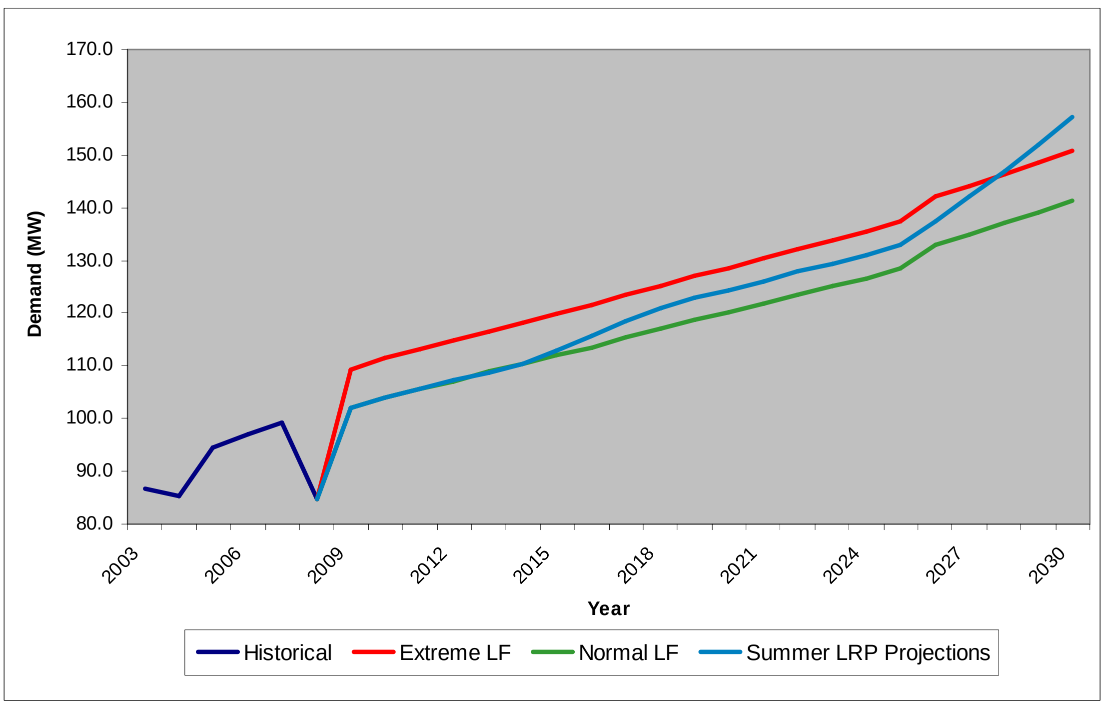

Figure 1-2 Summer Historical and Projected System Peak Demands

The 2008 EKPC LF was based on the 2007 winter peak load of 128.3 MW and the 2007 summer peak load of 99.2 MW. The winter and summer peaks have a compound annual load growth rate of 1.8% and 1.6%, respectively, through 2027.

From discussions with Clark Energy and the RUS representative, the extreme projections appeared to be more aggressive, initially, than the expectations due to the economic slow-down. The normal projections appeared to be on the low-side of load growth expectations. For the Long Range Plan (LRP), the load forecast projections were adjusted to reflect an initial load growth following the normal projections from the 2008 EKPC LF, and a long-term growth following extreme projections from the 2008 EKPC LF. As you can see in Table 1-3 the LRP is initially in line with the Normal LF but gradually goes towards the Extreme LF.

The 2010 – 2014 CWP design loads were based on the adjusted LF projections, or the LRP projections. The summer and winter system loads from the LF are compared to the LRP projections in Table 1-3.

Table 1-3
Load Forecast and LRP Comparison

	Summer				Winter			
Year	Actual (kW) CP	Normal LF(1)	Extreme LF(1)	LRP	Actual (kW) CP	Normal LF(1)	Extreme LF(1)	LRP
2000	82	-	-	-	95	-	-	-
2001	85	-	-	-	104	-	-	-
2002	89	-	-	-	94	-	-	-
2003	87	-	-	-	110	-	-	-
2004	85	-	-	-	111	-	-	-
2005	95	-	-	-	115	-	-	-
2006	97	-	-	-	108	-	-	-
2007	99	-	-	-	128	-	-	-
2008	84	-	-	-	130	-	-	-
2009	-	102.0	109.3	-	131	-	-	-
2010	-	104.0	111.4	105.6	-	133.3	149.6	-
2011	-	105.6	113.1	107.2	-	135.8	152.3	135.8
2012	-	107.2	114.8	108.8	-	138.5	155.3	138.5
2013	-	108.8	116.5	110.3	-	141.5	158.5	141.5
2014	-	110.3	118.1	112.9	-	143.9	161.1	143.9
2015	-	112.0	119.9	115.7	-	147.0	164.5	149.8
2016	-	113.5	121.5	118.3	-	149.7	167.4	155.7
2017	-	115.4	123.5	121.0	-	153.0	171.0	161.5
2018	-	117.0	125.2	122.8	-	155.7	173.9	167.4
2019	-	118.6	127.0	124.2	-	158.8	177.2	170.6
2020	-	120.0	128.5	126.1	-	161.6	180.2	173.5
2021	-	121.8	130.4	127.8	-	164.9	183.7	177.0
2022	-	123.5	132.1	129.4	-	167.8	186.6	180.1
2023	-	125.1	133.8	130.9	-	170.9	190.1	183.2
2024	-	126.5	135.3	133.0	-	173.4	192.9	185.9

	Summer				Winter			
Year	Actual (kW) CP	Normal LF(1)	Extreme LF(1)	LRP	Actual (kW) CP	Normal LF(1)	Extreme LF(1)	LRP
2025	-	128.6	137.5	137.5	-	177.0	196.7	189.6
2026	-	133.0	142.0	142.2	-	182.3	202.2	195.1
2027	-	134.5	144.3	147.0	-	186.0	206.2	200.8
2028	-	136.0	146.6	151.9	-	189.7	210.4	206.6
2029	-	137.5	148.9	157.1	-	193.5	214.6	212.6
2030	-	-	-	-	-	197.4	218.9	218.7

The LF data is from EKPC's 2008 Load forecast
The LRP was developed by from discussions with Clark Energy and the RUS representative

1.4.2 2007 Operations and Maintenance Survey

The Form 300 operations and maintenance review was performed by Clark Energy and the RUS field representative in September 2007. The review indicated a satisfactory rating in all areas except the following, which received an acceptable rating.

- Compliance with Safety Codes: Foreign Structures
- Observed Physical Condition from Field Checking: Right-of-Way

1.4.3 Sectionalizing Studies

R. W. Beck has recently completed the 2009 Distribution System Coordination Study for Clark Energy. Periodic reviews are recommended in order to locate potential coordination problems that can result from load growth or changes in the system characteristics.

Clark Energy reviews the coordination of all sectionalizing devices. Clark Energy will analyze the protection schemes of all new or significantly changed circuits due to CWP projects. Upon completion of the analyses, a list is prepared of reclosers, fuses, and other devices required to adequately protect the circuits investigated. This list of protection equipment additions and changes, and its estimated installed cost required for the next planning period, is included in Section 2 of this CWP.

1.5 Historical and Projected System Data

1.5.1 Annual Energy, Load, and Consumer Data

A summary of the annual energy, demand, and consumer information is given in Table 1-4. The historical data provided was taken from Clark Energy data. Projections for the 2013 CWP summer design load of 110.3 MW and the 2014 CWP winter design load of 143.9 MW. The total projected system load was allocated to individual substations and feeders based on Clark Energy's knowledge of the system, historical loading, and known future development.

Table 1-4
Historical and Projected Annual Energy, Demand, and Consumer Data

Calendar Year	Energy Purchased (MWh)	Energy Sold [2]		Energy Loss		Coincident Peak Demand [3]		Percent Increase	Annual Load Factor	Number of Customers [4]	
		(MWh)	Percent Increase	(MWh)	Percent of Purchases	Season	(kW)			Average [5]	Percent Increase
2001	401,373	372,213	-	28,652	7.14%	Winter	103,500	-	44.27%	23,427	-
2002	411,248	391,175	5.09%	19,551	4.75%	Winter	93,700	-9.47%	50.10%	23,977	2.35%
2003	418,275	392,455	0.33%	25,278	6.04%	Winter	110,300	17.72%	43.29%	24,376	1.66%
2004	427,871	401,986	2.43%	25,297	5.91%	Winter	112,200	1.72%	43.53%	24,796	1.72%
2005	449,841	428,774	6.66%	20,528	4.56%	Winter	114,500	2.05%	44.85%	25,151	1.43%
2006	446,178	420,158	-2.01%	25,374	5.69%	Winter	107,400	-6.61%	47.40%	25,508	1.42%
2007	468,537	444,403	5.77%	23,346	4.98%	Winter	128,300	19.46%	41.70%	25,801	1.15%
2008	470,284	445,982	0.36%	23,514	5.00%	Winter	129,800	1.17%	41.40%	26,074	1.06%
2009	489,574	464,306	4.11%	24,480	5.00%	Winter	130,100	0.23%	43.00%	26,480	1.56%
2010	500,778	474,951	2.29%	25,039	5.00%	Winter	133,300	2.46%	42.90%	26,881	1.51%
2011	509,868	483,586	1.82%	25,494	5.00%	Winter	135,800	1.88%	42.90%	27,276	1.47%
2012	520,887	494,055	2.16%	26,044	5.00%	Winter	141,500	4.20%	42.90%	27,657	1.40%
2013	529,560	502,293	1.67%	26,479	5.00%	Winter	143,900	1.70%	42.70%	28,033	1.36%
2014	538,080	510,338	1.60%	27,742	5.00%	Winter	149,800	4.10%	41.0%	28,419	1.37%

Notes:
(1) Historical and projected data based on 2008 EKPC LF.
(2) Does not include own use.
(3) Non-coincident peak for the system is the sum of the metered substation coincident peaks.
(4) Average number of customers for projected CWP period was based on LF projections.
(5) Includes residential, small commercial and large commercial customers.

1.6 Substation Load Data

Clark Energy purchases power from the EKPC at twenty 69-kV delivery points, two 138 kV delivery points, and 2 meter points. Table 1-5 summarizes the existing Clark Energy substations, configuration, voltage, and capacity. Historical winter and summer substation demands and power factor are shown in Tables 1-6 and 1-7. The substations are listed in Table 1-10 with the calculated capacity and existing and projected substation peak demands.

The total installed substation transformer capacity for the Clark Energy system is approximately 293 MVA in the winter and 212.5 MVA in the summer based on the current configuration and location of the transformers. The winter transformer capacity is 119% greater than the winter coincident system peak of 133.34 MW. The summer transformer capacity is 117% greater than the summer coincident peak of 97.64 MW. During the existing winter and summer peak, none of the substation transformers exceeded their ratings.

Table 1-5
Substation Voltages and Capacities

Substation	Voltage (kV)	Total Capacity (MVA)	Cal. Summer Capacity (MVA)	Cal. Winter Capacity (MVA)	Trans. Config. Qty.-Phase-Rating (MVA)
Blevins Valley	69-12.5	5.0	4.4	7.5	(3) 1ϕ - 1.667
Bowen	69-12.5	5.6	5.5	7.9	(3) 1ϕ - 1.667/1.867
Cave Run	69-12.5	2.0	1.8	3.0	(3) 1ϕ - 0.667
Clay City	69-12.5	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Frenchburg	69-12.5	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Hardwick's Creek	69-12.5	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
High Rock	69-12.5	1.0	1.0	1.4	(1) 1ϕ - 0.883
Hinkston	69-24.9	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Hope	69-24.9	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Hunt	69-24.9	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Jeffersonville	69-24.9	11.2	11.1	15.7	(1) 3ϕ - 11.2
Mariba	69-12.5	5.6	5.5	7.9	(3) 1ϕ - 1.667/1.867
Miller Hunt	69-24.9	11.2	11.1	15.7	(1) 3ϕ - 11.2
Mt. Sterling	69-12.5	11.2	11.1	15.7	(1) 3ϕ - 11.2
Reid Village	69-12.5	5.6	5.5	7.9	(3) 1ϕ - 1.667/1.867
Sideview	69-12.5	14.0	13.6	18.1	(1) 3ϕ - 11.2/14.0
Stanton	69-12.5	20.0	19.5	25.9	(1) 3ϕ - 15/20
Three Forks	138-24.9	12.0	11.9	16.8	(1) 3ϕ - 12
Trapp	69-12.5	5.0	4.4	7.5	(3) 1ϕ - 1.667

Substation	Voltage (kV)	Total Capacity (MVA)	Cal. Summer Capacity (MVA)	Cal. Winter Capacity (MVA)	Trans. Config. Qty.-Phase-Rating (MVA)
Treehaven	69-12.5	6.4	6.3	8.3	(3) 1ϕ - 1.667/1.867/2.13
Union City	138-24.9	12.0	11.9	16.8	(1) 3ϕ - 12
Van Meter	69-12.5	6.4	6.3	8.3	(3) 1ϕ - 1.667/1.867/2.13
TOTAL			212.50	293.00	

Table 1-6
Historical Winter Substation Demands

Substation	Cal. Winter Capacity(1) (MVA)	Coincident Peak(2) (MW)	Power Factor @ Peak(2)	Percent Loaded(3)
Blevins Valley	7.5	4.3	100%	57.6%
Bowen	7.9	4.1	100%	51.7%
Cave Run	3.0	1.7	99%	58.0%
Clay City (1)	17.1	11.0	99%	64.5%
Frenchburg (1)	14.4	9.3	99%	64.4%
Grayson Meter PT	0.1	0.1	100%	100.0%
Hardwick's Creek (1) (4)	14.4	3.5	100%	24.1%
High Rock	1.4	0.7	99%	50.5%
Hinkston (1) (4)	17.1	4.4	100%	25.4%
Hope (1)	8.9	6.1	99%	68.6%
Hunt (1)	13.7	10.7	99%	78.4%
Jeffersonville (1)	13.7	7.0	99%	51.0%
Mariba (1)	7.5	6.1	99%	81.3%
Miller Hunt (4)	15.7	3.0	100%	19.1%
Mt. Sterling (1)	13.7	6.9	100%	50.6%
Reid Village (1)	6.8	4.2	99%	61.9%
Sideview (1)	14.4	9.5	99%	66.2%
Stanton (1)	23.6	12.5	100%	53.0%
Three Forks	16.8	6.4	99%	37.9%
Trapp (1)	6.8	3.6	99%	52.7%
Treehaven (1)	7.5	3.7	100%	49.9%
Union City	16.8	11.0	99%	65.1%
Van Meter	8.3	3.6	99%	42.7%

Notes:
(1) Based on ratings provided by EKPC for the limiting capacity factor at each substation, other than the substation transformer. It may be the regulator, tap changer, or high-side fuse.
(2) Peak demand and power factor based on historical metered data provided by EKPC for January 2009 and load transfers from the engineering model.
(3) Loading percentage stated as coincident peak and power factor to the calculated winter capacities.
(4) Substation not in service at time of peak, and power factor was assumed based on readings from adjacent substations.

Table 1-7
Historical Summer Substation Demands

Substation	Cal. Summer Capacity (1) (MVA)	Coincident Peak(2) (MW)	Power Factor @ Peak (2)	Percent Loaded (3)
Blevins Valley	4.4	2.9	99%	66.5%
Bowen	5.5	4.0	94%	71.3%
Cave Run	1.8	1.3	96%	74.4%
Clay City	13.6	9.3	95%	68.5%
Frenchburg	13.6	7.5	95%	54.8%
Grayson Meter PT	0.1	0.03	100%	26.0%
Hardwick's Creek (4)	13.6	2.4	98%	17.2%
High Rock	1.0	0.6	94%	53.6%
Hinkston	13.6	3.5	87%	25.9%
Hope (1)	8.9	4.4	94%	49.8%
Hunt	13.6	6.2	96%	45.7%
Jeffersonville	11.1	4.8	94%	43.4%
Mariba (1)	4.9	4.0	96%	81.0%
Miller Hunt	11.1	2.3	98%	20.7%
Mt. Sterling (1)	9.8	4.8	97%	48.7%
Reid Village (1)	4.9	3.5	94%	72.1%
Sideview	13.6	5.0	94%	38.3%
Stanton	19.5	14.0	95%	72.0%
Three Forks	11.9	3.5	94%	29.1%
Trapp	4.4	2.4	94%	54.9%
Treehaven (1)	4.9	3.5	98%	70.6%
Union City	11.9	5.2	95%	43.8%
Van Meter	6.3	2.4	94%	38.9%

Notes:
(1) Based on ratings provided by EKPC for the limiting capacity factor at each substation, other than the substation transformer. It may be the regulator, tap changer, or high-side fuse.
(2) Peak demand and power factor based on historical metered data provided by EKPC for July 2007 and load transfers from the engineering model.
(3) Loading percentage stated as coincident peak and power factor to the calculated summer capacities.
(4) Substation not in service at time of peak, and power factor was assumed based on readings from adjacent substations.

1.7 Circuit Loads

The distribution system is served through (47) 12.47/7.2 kV and (25) 24.9/14.4 kV substation reclosers. The recloser continuous current rating and the conductor capacity of the backbone conductors on the feeder are compared to the winter and summer peak feeder loads in Tables 1-8 and 1-9.

Based on the existing peak loads from the distribution system model, High Rock was the only substation recloser to exceed the rated capacity. During the summer peak, Frenchburg Circuit 3, Mt. Sterling Circuit 3, Reid Village Circuit 2, and Van Meter Circuit 3 exceed the backbone conductor planning capacity. During the winter peak, none of the substation circuits exceeded the backbone conductor capacity.

Table 1-8
Recloser and Feeder Capacity at 2007 Summer Peak

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Blevins Valley					
1	71.5	560	12.8%	336 ACSR	8.1%
2	111.1	560	19.8%	1/0 CU	41.5%
3	21.8	560	3.9%	1/0 CU	7.5%
Bowen					
1	78.7	560	14.1%	1/0 ACSR	36.9%
2	77.1	560	13.8%	1/0 ACSR	40.5%
3	55.1	560	9.8%	397 ACSR	11.0%
Cave Run					
1	54.8	560	9.8%	4/0 ACSR	19.0%
2	56.0	560	10.0%	4/0 ACSR	19.7%
Clay City					
1	173.6	560	31.0%	397 ACSR	35.4%
2	154.0	560	27.5%	397 ACSR	31.4%
3	124.1	560	22.0%	336 ACSR	29.1%
4	146.7	560	26.2%	336 ACSR	33.2%
Frenchburg					
1	56.2	560	10.0%	336 ACSR	12.7%
2	74.1	560	13.2%	1/0 CU	29.1%
3	214.0	560	38.2%	1/0 CU	76.6%
4	87.9	560	15.7%	336 ACSR	19.9%
Grayson Meter					
1	3.9	15	26%	2 ACSR	2.5%
Hardwick's					
1	104.9	560	18.7%	336 ACSR	23.7%
2	34.3	560	6.1%	336 ACSR	7.8%
3	26.1	560	4.7%	336 ACSR	5.8%
High Rock					
1(3)	78.3	70	111.9%	1/0 ACSR	39.0%
Hinkston					
1	13.4	560	2.4%	1/0 ACSR	7.9%
2	32.7	560	5.8%	1/0 ACSR	15.9%
3	34.2	560	6.1%	4/0 ACSR	11.0%
4	13.3	560	2.4%	336 ACSR	3.0%

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Hope					
1	15.7	560	2.81%	1/0 CU	5.6%
2	39.5	560	7.06%	1/0 CU	14.9%
3	94.2	560	16.82%	336 ACSR	21.2%
Hunt					
1	35.0	560	6.2%	397 ACSR	7.1%
2	12.6	560	2.3%	1/0 ACSR	12.6%
3	62.0	560	11.1%	1/0 ACSR	30.6%
4	66.8	560	11.9%	397 ACSR	13.6%
Jeffersonville					
1	83.1	560	14.8%	336 ACSR	18.7%
2	56.9	560	10.2%	336 ACSR	12.9%
Mariba					
1	36.8	560	6.6%	1/0 ACSR	18.3%
2	140.6	560	25.1%	1/0 ACSR	35.0%
3	54.9	560	9.8%	1/0 ACSR	24.8%
4 (4)	32.6	70	57.0%	4 ACSR	27.4%
Miller Hunt					
1	54.8	560	9.8%	336 ACSR	6.8%
2	27.4	560	4.9%	336 ACSR	5.5%
3	4.9	560	0.9%	336 ACSR	1.0%
Mt. Sterling					
1	79.8	560	14.3%	4/0 ACSR	28.0%
2	118.2	560	21.1%	4/0 ACSR	26.8%
3	108.1	560	19.3%	1/0 ACSR	53.3%
Reid Village					
1	188.6	560	33.7%	4 ACSR	42.7%
2	118.7	560	21.2%	1/0 ACSR	59.0%
Sideview					
1	33.1	560	5.9%	1/0 ACSR	16.5%
2	45.6	560	8.1%	4/0 ACSR	16.0%
3	71.5	560	12.8%	4/0 ACSR	25.1%
4	76.5	560	13.7%	4/0 ACSR	26.8%
Stanton					
1	165.7	560	29.6%	336 ACSR	37.5%
2	137.2	560	24.5%	336 ACSR	31.8%
3	207.3	560	37.0%	397 ACSR	42.0%
4	118.0	560	21.1%	397 ACSR	24.0%
5	187.2	560	33.4%	336 ACSR	42.4%

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Three Forks					
1	41.3	560	7.4%	1/0 ACSR	20.6%
2	65.1	560	11.6%	1/0 ACSR	32.4%
3	15.8	560	2.8%	336 ACSR	3.2%
Trapp					
1	51.7	560	9.2%	1/0 ACSR	25.7%
2	61.8	560	11.0%	336 ACSR	14.0%
3	39.4	560	7.0%	336 ACSR	8.9%
Treehaven					
1	43.1	560	7.7%	1/0 ACSR	21.5%
2	97.6	560	17.4%	1/0 ACSR	46.9%
3	10.8	560	1.9%	336 ACSR	2.5%
4	37.6	560	6.7%	336 ACSR	8.5%
Union City					
1	48.6	560	8.7%	336 ACSR	11.0%
2	36.0	560	6.4%	336 ACSR	8.1%
3	29.8	560	5.3%	336 ACSR	6.7%
4	44.3	560	7.9%	336 ACSR	10.0%
Van Meter					
1	25.8	560	4.6%	4 ACSR	21.7%
2	14.1	560	2.5%	1/0 ACSR	7.0%
3	110.5	560	19.7%	1/0 ACSR	55.0%

Notes:
(1) Based on historical metered data provided by EKPC for July 2007 and load transfers from the engineering model.
(2) Based on the engineering model.
(3) High Rock is single-phase and is limited by the high-side transformer fuse.
(4) Mariba Circuit 4 is a single-phase 70 Amp recloser.

Table 1-9
Recloser and Feeder Capacity at 2009 Winter Peak

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Blevins Valley					
1	94.9	560	16.9%	336 ACSR	6.5%
2	148.7	560	26.6%	1/0 CU	32.1%
3	37.9	560	6.8%	1/0 CU	7.9%
Bowen					
1	89.2	560	15.9%	1/0 ACSR	26.1%
2	74.4	560	13.3%	1/0 ACSR	20.5%
3	56.3	560	10.0%	397 ACSR	6.5%

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Cave Run					
1	40.6	560	7.3%	4/0 ACSR	8.4%
2	89.0	560	15.9%	4/0 ACSR	7.6%
Clay City					
1	201.5	560	36.0%	397 ACSR	24.7%
2	193.4	560	34.5%	397 ACSR	23.7%
3	125.1	560	22.3%	336 ACSR	20.3%
4	171.8	560	30.7%	336 ACSR	23.5%
Frenchburg					
1	91.1	560	16.3%	336 ACSR	12.5%
2	97.0	560	17.3%	1/0 CU	21.5%
3	140.3	560	25.1%	1/0 CU	28.6%
4	145.9	560	26.1%	336 ACSR	20.0%
Grayson Meter					
1	13.9	15	92.7%	2 ACSR	5.5%
Hardwick's					
1	158.6	560	26.1%	336 ACSR	21.7%
2	34.8	560	6.22%	336 ACSR	4.8%
3	41.1	560	7.3%	336 ACSR	5.2%
High Rock					
1 (3)	93.9	70	134%	1/0 ACSR	28.5%
Hinkston					
1	13.8	560	2.5%	1/0 ACSR	4.2%
2	48.7	560	8.7%	1/0 ACSR	14.6%
3	49.9	560	8.9%	4/0 ACSR	10.1%
4	14.6	560	2.6%	336 ACSR	2.0%
Hope					
1	14.6	560	2.6%	1/0 CU	3.3%
2	44.4	560	7.9%	1/0 CU	9.5%
3	135.1	560	24.1%	336 ACSR	18.5%
Hunt					
1	62.0	560	11.1%	397 ACSR	7.3%
2	23.3	560	4.2%	1/0 ACSR	14.1%
3	93.2	560	16.6%	1/0 ACSR	26.6%
4	110.2	560	19.7%	397 ACSR	13.5%
Jeffersonville					
1	119.1	560	21.3%	336 ACSR	16.2%
2	69.3	560	12.4%	336 ACSR	8.8%

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Mariba					
1	56.1	560	10.0%	1/0 ACSR	17.4%
2	212.5	560	38.0%	1/0 ACSR	32.2%
3	86.3	560	15.4%	1/0 ACSR	24.8%
4 (4)	60.7	70	86.7%	4 ACSR	31.2%
Miller Hunt					
1	64.0	560	11.4%	336 ACSR	5.7%
2	36.5	560	6.5%	336 ACSR	4.8%
3	5.2	560	0.9%	336 ACSR	0.7%
Mt. Sterling					
1	81.8	560	14.6%	4/0 ACSR	17.4%
2	173.4	560	31.0%	4/0 ACSR	23.8%
3	159.9	560	28.5%	1/0 ACSR	47.2%
Reid Village					
1	243.5	560	43.5%	336 ACSR	33.4%
2	109.0	560	19.5%	1/0 ACSR	32.3%
Sideview					
1	66.7	560	11.9%	1/0 ACSR	19.6%
2	72.2	560	12.9%	4/0 ACSR	13.1%
3	125.0	560	22.3%	4/0 ACSR	26.6%
4	141.6	560	25.3%	4/0 ACSR	28.5%
Stanton					
1	121.1	560	21.6%	336 ACSR	16.6%
2	122.1	560	21.8%	336 ACSR	15.8%
3	173.1	560	30.9%	397 ACSR	21.0%
4	84.1	560	15.0%	397 ACSR	10.3%
5	178.6	560	31.9%	336 ACSR	24.5%
Three Forks					
1	69.0	560	12.3%	1/0 ACSR	19.8%
2	119.2	560	21.3%	1/0 ACSR	36.1%
3	29.3	560	5.2%	336 ACSR	3.7%
Trapp					
1	76.0	560	13.6%	1/0 ACSR	20.9%
2	92.2	560	16.5%	336 ACSR	12.5%
3	39.1	560	7.0%	336 ACSR	5.4%
Treehaven					
1	38.8	560	6.9%	1/0 ACSR	13.0%
2	95.2	560	17.0%	1/0 ACSR	28.4%
3	23.3	560	4.2%	336 ACSR	3.2%
4	66.2	560	11.8%	1/0 ACSR	9.1%

Substation /Feeder	Load (1) (Amps)	Recloser Rating (Amps)	Percent Recloser Loading	Backbone Conductor(2)	Percent Conductor Loading (2)
Union City					
1	97.3	560	17.4%	336 ACSR	13.3%
2	64.9	560	11.6%	336 ACSR	8.9%
3	58.1	560	10.4%	336 ACSR	8.0%
4	109.5	560	19.6%	336 ACSR	14.75%
Van Meter					
1	40.5	560	7.2%	4 ACSR	20.2%
2	15.8	560	2.8%	1/0 ACSR	4.6%
3	143.0	560	25.5%	1/0 ACSR	42.7%

Notes:
(1) Based on historical metered data provided by EKPC for January 2009 and load transfers from the engineering model.
(2) Based on the engineering model.
(3) High Rock is single-phase and is limited by the high-side transformer fuse.
(4) Mariba Circuit 4 is a single-phase 70 Amp recloser.

A review of Tables 1-10 and 1-11 provides an overview of the existing transformer capacity compared to the projected CWP winter design load in 2014 and summer design load in 2013.

Table 1-10
Existing Substation Transformer Capacity
and Winter Projected Loading

Substation /Feeder	Peak Load (MW)			
	Cal. Winter Capacity (1) (MVA)	Projected 2014 (2) (MW)	Power Factor @Peak(3)	Percent Loaded(4)
Blevins Valley	7.5	4.6	100%	61.3%
Bowen	7.9	4.1	100%	51.9%
Cave Run	3.0	1.8	99%	60.6%
Clay City (1)	17.1	11.8	99%	69.7%
Frenchburg (1)	14.4	9.7	99%	68.0%
Hardwick's Creek (1) (4)	14.4	3.8	100%	26.4%
High Rock	1.4	0.7	99%	50.5%
Hinkston (1) (4)	17.1	4.7	100%	27.5%
Hope (1)	8.9	6.7	99%	76.0%
Hunt (1)	13.7	11.7	99%	86.3%
Jeffersonville (1)	13.7	7.6	99%	56.0%
Mariba (1)	7.5	6.7	99%	90.2%
Miller Hunt (4)	15.7	3.3	100%	21.0%
Mt. Sterling (1)	13.7	7.6	100%	55.5%
Reid Village (1)	6.8	4.6	99%	68.3%

Substation /Feeder	Peak Load (MW)			
	Cal. Winter Capacity (1) (MVA)	Projected 2014 (2) (MW)	Power Factor @Peak(3)	Percent Loaded(4)
Sideview (1)	14.4	10.4	99%	73.0%
Stanton (1)	23.6	13.1	100%	55.5%
Three Forks	16.8	6.8	99%	40.9%
Trapp (1)	6.8	3.9	99%	57.9%
Treehaven (1)	7.5	3.9	100%	52.0%
Union City	16.8	12.5	99%	75.2%
Van Meter	8.3	3.9	99%	47.5%

Notes:

(1) Based on ratings provided by EKPC for the limiting capacity factor at each substation, other than the substation transformer. It may be the regulator, tap changer, or high-side fuse.

(2) Projected demand based on the adjusted 2008 EKPC LF.

(3) Power factor based on historical metered data provided by EKPC for January 2009 and from load transfers from the engineering model.

(4) Loading percentage stated as load projection and power factor to the calculated winter capacities.

Table 1-11
Existing Substation Transformer Capacity and Summer Projected Loading

Substation /Feeder	Peak Load (MW)			
	Cal. Summer Capacity (1) (MVA)	Projected 2013 (2) (MW)	Power Factor @Peak(3)	Percent Loaded(4)
Blevins Valley	4.4	3.3	99%	75.8%
Bowen	5.5	4.0	94%	77.4%
Cave Run	1.8	1.4	96%	81.0%
Clay City	13.6	10.5	95%	81.3%
Frenchburg	13.6	8.0	95%	61.9%
Hardwick's Creek (4)	13.6	2.7	100%	19.9%
High Rock	1.0	0.6	98%	61.2%
Hinkston	13.6	4.1	94%	32.1%
Hope (1)	8.9	5.1	87%	65.9%
Hunt	13.6	7.2	94%	56.3%
Jeffersonville	11.1	5.6	96%	52.6%
Mariba (1)	4.9	4.6	94%	99.9%
Miller Hunt	11.1	2.7	96%	25.3%
Mt. Sterling (1)	9.8	5.5	98%	57.3%
Reid Village (1)	4.9	4.1	97%	86.3%
Sideview	13.6	6.1	94%	47.7%
Stanton	19.5	15.1	94%	82.4%
Three Forks	11.9	3.9	95%	34.5%

Substation /Feeder	Peak Load (MW)			
	Cal. Summer Capacity (1) (MVA)	Projected 2013 (2) (MW)	Power Factor @Peak(3)	Percent Loaded(4)
Trapp	4.4	2.8	94%	67.7%
Treehaven (1)	4.9	3.7	94%	80.3%
Union City	11.9	6.5	98%	55.7%
Van Meter	6.3	2.8	95%	46.8%

Notes:
(1)Based on ratings provided by EKPC for the limiting capacity factor at each substation, other than the substation transformer. It may be the regulator, tap changer, or high-side fuse.
(2) Projected demand based on the adjusted 2008 EKPC LF.
(3) Power factor based on historical metered data provided by EKPC for July 2007 and from load transfers from the engineering model.
(4) Loading percentage stated as load projection and power factor to the calculated summer capacities.

Table 1-12
New Substation Transformer Capacity
Summer and Winter Projected Loading

Substation /Feeder	Peak Load (MW)			
	Cal. Capacity (1) (MVA)	Projected 2014 (2) (MW)	Power Factor @Peak(3)	Percent Loaded(4)
	Winter			
Sideview (1)	14.4	6.6	99%	46.3%
Stone Rd (6)	7.5	0.9	----	12.0%(5)
	Summer			
Sideview	13.6	4.3	94%	33.6%
Stone Rd (6)	4.4	0.4	----	9.1%(5)

Notes:
(1) Based on ratings provided by EKPC for the limiting capacity factor at each substation, other than the substation transformer. It may be the regulator, tap changer, or high-side fuse.
(2) Projected demand based on the adjusted 2008 EKPC LF.
(3) Power factor based on historical metered data provided by EKPC for January 2009 and from load transfers from the engineering model.
(4) Loading percentage stated as load projection and power factor to the calculated winter capacities.
(5) New substations do not include power factor in loading percentage
(6) Stone Rd. is scheduled to be built in Load Level 1

The Clark Energy electric system is modeled on Milsoft Integrated Solutions, Inc.'s WindMil™ software. Load data were obtained from the Clark Energy member billing information. Load flows were prepared to provide information such as the percent conductor loading to its capacity, calculated line losses, power factor information, and voltage drop along line sections. The load-flow information from the computer model was compared to the criteria outlined in this report. Recommendations were then based on these results.

Each of the 72 circuits was analyzed with respect to adequate voltage and loading conditions. The computer analysis of the 2009 winter system peak revealed:

- Voltage levels less than 118 Volts in line sections in the following substations: Blevins Valley – Circuit 2; Frenchburg – Circuit 1; Mariba – Circuit 3; Mt. Sterling – Circuit 3; Reid Village – Circuit 1; Sideview – Circuit 3 and 4; Van Meter – Circuit 3.
- Conductor loading greater than 50% in line sections in the following substations: Sideview – Circuit 3
- Greater than 56 Amps on single-phase line sections in the following substations: Clay City – Circuit 2; Hardwick's Creek – Circuit 1; High Rock – Circuit 1; Hunt – Circuit 3; Mariba – Circuit 4; Sideview – Circuit 1; Van Meter – Circuit 3;

The computer analysis of the 2007 summer system peak revealed:

- Voltage levels less than 118 Volts in line sections in the following substations: Sideview – Circuit 3; Reid Village – Circuit 1; Stanton – Circuit 3
- Conductor loading greater than 50% in line sections in the following substations: Bowen – Circuit 1; Clay City – Circuits 1 and 2; Frenchburg – Circuit 3; Hardwick's Creek – Circuit 1; Mt. Sterling – Circuit 3; Reid Village – Circuit 2; Stanton – Circuit 3; Treehaven – Circuit 2; Van Meter – Circuit 3.
- Greater than 56 Amps on single-phase line sections in the following substations: High Rock – Circuit 1

Computer analysis of the projected 2013 winter system peak revealed:

- Voltage levels lower than 118 Volts in line sections in the following substations: Blevins Valley – Circuit 2; Frenchburg – Circuit 1; Mariba – Circuit 3; Mt. Sterling – Circuit 3; Reid Village – Circuit 1; Sideview – Circuit 3 and 4; Van Meter – Circuit 3.
- Conductor loading greater than 50% in line sections in the following substations: Sideview – Circuit 3; Mt. Sterling – Circuit 3; Stanton – Circuit 3; Hardwick's Creek – Circuit 1
- Greater than 56 Amps on single-phase line sections in the following substations: Clay City – Circuit 2 and 4; Hardwick's Creek – Circuit 1; High Rock – Circuit 1; Hunt – Circuit 3; Mariba – Circuit 4; Sideview – Circuit 1; Van Meter – Circuit 3;.

Computer analysis of the projected 2013 summer system peak revealed:

- Voltage levels lower than 118 Volts in line sections in the following substations: Sideview – Circuit 3; Reid Village – Circuit 1; Stanton – Circuit 3

- Conductor loading greater than 50% in line sections in the following substations: Bowen – Circuit 1; Clay City – Circuits 1 and 2; Frenchburg – Circuit 3; Hardwick's Creek – Circuit 1; Mt. Sterling – Circuit 3; Reid Village – Circuit 1 and 2; Sideview – Circuit 3; Stanton – Circuit 3; Treehaven – Circuit 2; Van Meter – Circuit 3.
- Greater than 56 Amps on single-phase line sections in the following substations: Clay City – Circuit 2; Hardwick's Creek – Circuit 1; High Rock – Circuit 1;

1.8 System Outages

A summary of the outages experienced by Clark Energy for the last five years is given in Table 1-12. The five-year average annual outage hour per customer is 2.30 hours. RUS suggests a system goal for outages of less than two hours per customer in rural areas and one hour in urban areas. Clark Energy's goal is to improve system reliability and keep the average outage hours per customer below the recommended guideline.

Table 1-13
Service Interruption Summary
Average Hours Per Consumer By Cause

Year	Power Supplier	Extreme Storm	Prearranged	Others	Total
2004	0.18	0.00	0.02	2.83	3.03
2005	0.30	0.00	0.01	1.01	1.32
2006	0.04	0.00	0.03	1.71	1.78
2007	0.28	0.00	0.03	1.58	1.89
2008	0.42	0.00	0.03	3.04	3.49
5 Yr. Avg.	0.24	0.00	0.02	2.03	2.30

Note:
From RUS Form 7.

1.9 Long Range Plan

The 2010 Long Range Plan (LRP) was prepared in conjunction with the 2010-2014 Construction Work Plan. The purpose of the LRP is to provide general guidance for system expansion. Periodic reviews of the LRP will be required to examine the applicability of the preferred plan considering actual system developments. Detailed construction work plans should be prepared for the necessary construction, and the LRP should be reevaluated as each work plan is prepared.

Section 2
REQUIRED CONSTRUCTION ITEMS

The required 2010 - 2014 CWP items are discussed in this section. The design criteria as given in Section 1 were used as a guide to identify potential CWP items for evaluation. Load-flow, voltage drop, and where appropriate, economic analysis was performed to support the recommended CWP items.

2.1 Service to New Members

Historical information was reviewed for a 24-month period from calendar years 2007 and 2008 to project new member service requirements for the CWP period. The historical number of members was increased approximately 1.2% per year for the 2010 - 2014 CWP period. The historical costs were inflated by 3.5% per year.

Table 2-1
Construction Required to Serve New Members

Estimated 48-Month Work Plan Period						
New Members - System Wide	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Number of New Services						
Underground	205	207	210	212	215	844
Overhead	313	317	321	324	328	1,290
Total New Services	518	524	531	536	543	2,134
Linear Feet of New Underground Line						
Primary	26,929	27,252	27,579	27,910	28,245	110,986
Secondary	1,548	1,567	1,585	1,604	1,604	6,380
Service Drop	25,522	25,828	26,138	26,452	26,769	105,187
Subtotal	53,999	54,647	55,302	55,966	56,638	222,553
Average Length in Feet/UG Member	263.4	264.0	263.3	264.0	263.4	263.7
Linear Feet of New Overhead Line						
Primary	55,349	56,013	56,685	57,366	58,054	228,118
Secondary	7,738	7,831	7,925	8,020	8,116	31,892
Service Drop	17,348	17,556	17,767	17,980	18,196	71,499
Subtotal	80,435	81,400	82,377	83,366	84,366	331,509
Average Length in Feet/OH Member	257.0	256.8	256.6	257.3	257.2	257.0

Estimated 48-Month Work Plan Period						
New Members - System Wide	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Total New Line (Linear Feet)	134,434	136,047	137,679	139,332	141,004	554,062
Cost of New Line						
Underground	$419,848	$439,875	$461,790	$482,512	$506,540	$1,890,717
Average Cost/UG Member	$2,053	$2,125	$2,199	$2,276	$2,356	$2,240
Overhead	$738,449	$775,382	$812,451	$848,880	$889,536	$3,326,249
Average Cost/OH Member	$2,363	$2,446	$2,531	$2,620	$2,712	$2,578
Total Cost of New Line	$1,158,297	$1,215,257	$1,274,241	$1,331,392	$1,396,076	$5,216,966
Number of New Transformers						
Padmount	87	88	89	90	91	358
Pole Mount	185	187	189	192	194	762
Total New Transformers	272	275	278	282	285	1,120
Average Installed Cost/Transformer						
Padmount	$1,800	$1,863	$1,928	$1,996	$2,066	$1,964
Pole Mount	$1,031	$1,067	$1,104	$1,143	$1,183	$1,125
Cost of Transformers						
Padmount	$156,600	$163,944	$171,592	$179,640	$188,006	$703,182
Pole Mount	$190,735	$199,529	$208,656	$219,456	$229,502	$857,143
Total Cost Of New Transformers	$347,335	$363,473	$380,248	$399,096	$417,508	$1,560,325
Number of New Meters						
Underground	205	207	210	212	215	844
Overhead	313	317	321	324	328	1,290
Total New Meters	518	524	531	536	543	2,134
Average Installed Cost/Meter						
Underground	$146	$151	$156	$162	$168	$159
Overhead	$147	$152	$157	$163	$169	$160
Cost of Meters						
Underground	$29,930	$31,257	$32,760	$34,344	$36,120	$134,481
Overhead	$46,011	$48,184	$50,397	$52,812	$55,432	$206,825
Total Cost Of New Meters	$75,941	$79,441	$83,157	$87,156	$91,552	$341,306
TOTAL COST OF NEW SERVICES	$1,581,573	$1,658,171	$1,737,646	$1,817,644	$1,905,136	$7,118,597

Table 2-2
Summary of Costs to Serve a New Member

RUS Code	Category Description	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
101	UG Lines - New Members	$439,875	$461,790	$482,512	$506,540	$1,890,717
102	OH Lines - New Members	$775,382	$812,451	$848,880	$889,536	$3,326,249
100	Total New Lines	$1,215,257	$1,274,241	$1,331,392	$1,396,076	$5,216,966
601	UG Transformers - New Members	$163,944	$171,592	$179,640	$188,006	$703,182
601	OH Transformers - New Members	$199,529	$208,656	$219,456	$229,502	$857,143
601	Meters - New Members	$79,441	$83,157	$87,156	$91,552	$341,306
601	Total Transformers and Meters	$442,914	$463,405	$486,252	$509,060	$1,901,631

2.2 Service Changes to Existing Members

Historical information was reviewed for a 24-month period from calendar years 2007 and 2008 to project service change requirements to existing members for the CWP period. The historical number of services was increased approximately 1.2% per year for the 2010 - 2014 CWP period. The historical costs were inflated by 3.5% per year.

Table 2-3
Construction Required for Service Changes to Existing Members

Estimated 48-Month Work Period						
Service Charges to Existing Members	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Service Drop Upgrades						
Number of Service Drop Upgrades						
Underground & Overhead	73	74	75	76	77	302
TOTAL SERVICE UPGRADES	73	74	75	76	77	302
Average Cost/Service Drop Upgrade						
Underground & Overhead	$1,423	$1,473	$1,524	$1,578	$1,633	$1,553
Cost of Service Drop Upgrades						
Underground & Overhead	$103,879	$109,002	$114,300	$119,928	$125,741	$468,971
TOTAL COST OF SERVICE UPGRADES	$103,879	$109,002	$114,300	$119,928	$125,741	$468,971
Number of Transformer Replacements						
Underground	0	0	0	0	0	0
Overhead	0	0	0	0	0	0
Total Transformer Replacements	0	0	0	0	0	0

Estimated 48-Month Work Period						
Service Charges to Existing Members	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Average Cost/Transformer Replacement						
Underground	$0	$0	$0	$0	$0	$0
Overhead	$0	$0	$0	$0	$0	$0
Cost of Transformers						
Underground	$0	$0	$0	$0	$0	$0
Overhead	$0	$0	$0	$0	$0	$0
TOTAL COST OF TRANSFORMER REPLACEMENTS	$0	$0	$0	$0	$0	$0
Number of Meter Replacements						
Underground & Overhead	1,000	1,000	1,000	1,000	1,000	4,000
Total Meter Replacements	1,000	1,000	1,000	1,000	1,000	4,000
Average Cost/Meter Replacement						
Underground & Overhead	$146	$151	$156	$162	$168	$159
Cost of Meters						
Underground & Overhead	$146,000	$151,000	$156,000	$162,000	$168,000	$637,000
TOTAL COST OF METER REPLACEMENTS	$146,000	$151,000	$156,000	$162,000	$168,000	$637,000

Table 2-4
Summary of Costs for Service Changes

RUS Code	Category Description	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
602	Total Service Drops	$109,002	$114,300	$119,928	$125,741	$468,971
601	Total Transformer Replacements	$0	$0	$0	$0	$0
601	Total Meter Replacements	$151,000	$156,000	$162,000	$168,000	$637,000

2.3 Poles

Clark Energy replaces all poles found to be physically deteriorated by inspection. An average of 311 poles per year required replacement during the 24-month period from calendar years 2007 and 2008. For the CWP period, it was estimated that a total of 1,587 poles will be replaced due to poor physical condition.

Listed below is a summary of pole replacement cost for the 2010 – 2014 CWP period. The historical number of poles was increased approximately 10.0% per year, because the historical values recorded in 2007 and 2008 reflect a relatively low number of replaced poles from the third system rotation. The equipment costs were inflated by 3.5% per year.

Table 2-5
Poles

	Estimated 48-Month Work Period					
	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Pole Replacements						
Number of Pole Replacements	311	342	376	414	455	1,587
Average Cost/Pole Replacement	$1,737	$1,798	$1,861	$1,926	$1,993	$1,902
TOTAL COST OF POLES	$540,207	$614,916	$699,736	$797,364	$906,815	$3,018,831

Summary of Costs for Pole Replacements

RUS Code	Category Description	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
606	Pole Replacements	$614,916	$699,736	$797,364	$906,815	$3,018,831
606	Total Pole Replacements	$614,916	$699,736	$797,364	$906,815	$3,018,831

2.4 Security Lights

For the 24-month period from calendar years 2007 and 2008, Clark Energy has installed an average of 369 security lights per year at an average cost of $294 each. Clark Energy estimates that the cost will increase 3.5% a year during the CWP period. A summary of the security light costs for the 2010 – 2014 CWP period is given below.

Table 2-6
Miscellaneous Construction

	Estimated 48-Month Work Period					
	Average 2007-2008	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
Security Lights						
Number of Security Lights	369	369	369	369	369	1,476
Average Cost/Security Lights	$294	$304	$315	$326	$337	$321
TOTAL COST OF SECURITY LIGHTS	$108,486	$112,176	$116,235	$120,294	$124,353	$473,058

Summary of Costs for Miscellaneous Construction

RUS Code	Category Description	2010-2011	2011-2012	2012-2013	2013-2014	TOTAL
702	Security Lights	$112,176	$116,235	$120,294	$124,353	$473,058

2.5 SCADA

A SCADA system will be implemented in a cooperative venture with East Kentucky Power Cooperative to increase reliability and gain robust data logging and archiving capabilities. The SCADA system will provide quicker access to fault information and proactive alarms to power quality issues. Having the ability to monitor and control circuit status will increase productivity during outages and routine maintenance of the system. The following improvement is recommended for the 2010 - 2014 CWP.

- RUS CODE 704-2 Carry-Over $218,000 over LL1-LL2

Description: Install SCADA equipment at every substation in the Clark Energy service territory.

2.6 AMR/AMI

- RUS CODE - 601 $169,300 over LL1-LL4

Description: Upgrade meters with built in remote disconnect device. This would give Clark Energy the ability to disconnect\reconnect the meter from the Winchester Office. This includes 500 units.

- RUS CODE - 705-1 $1,559,800 over LL1-LL4

Description: Upgrade all substations with two-way communications for the Hunt TS2 system. This will allow Clark Energy to continue to use the existing TS1 meters and upgrade to TS2 meters as new meters are purchased. With the implementation of the Hunt TS2 system, Clark Energy would have voltage information and two way communication capability from each meter. Additionally, the upgrade would allow Clark Energy to implement time of use rates. Cost estimates for the AMR/AMI upgrades are detailed in Exhibit 3.

2.7 Radio Communication

- RUS CODE 615-1 $545,000 over LL1-LL2

Description: Due to new FCC regulations, Clark Energy is required to replace the existing radio system. The commission ruled that all private land mobile radio users operating below 512 MHz must move to 12.5 kHz narrowband voice channels and highly efficient data channel operations by the end of 2012. Cost estimates for the Radio Communication upgrades are detailed in Exhibit 3.

2.8 Conversion and Line Changes

Conversion and line changes to existing lines were recommended to reduce voltage drop or relieve conductor loading. Switching load to other feeders was also evaluated when appropriate. Line regulators were considered as an alternative to improve voltage drop problems; however, no more than two line regulators were used in series.

Line and equipment costs were inflated by 3.5% per year based on the anticipated year of construction. Costs of carry-over projects were updated based on the existing line and equipment costs. The following conversions and line changes were recommended for the 2010 - 2014 CWP.

Clay City – Circuit 1

- **RUS CODE - 378** **$148,500 in LL1**
- **PROJECT NAME – Virden Ridge-336**

Description: From the Clay City Substation, extend 1,800 ft of 336 ACSR to the intersection of line sections PL.10953 and PL.48919. Transfer line section PL.48919 from Clay City Circuit 1 to the new Circuit 5. Reconductor and multi-phase line section PL.48921 to PL.48919 with three-phase 336 ACSR for approximately 3,200 feet. Reconductor line section PL.11553 with three-phase 336 ACSR for approximately 280 feet. Transfer section PL.52348 to PL.11553. Transfer the following single-phase taps:

Element Name	From	To
PL.27062	C	B
PL.27054	C	A
PL.45244	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Clay City Circuit 1 were loaded up to 56% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 37%.

Sectionalizing: The 5th circuit at Clay City Substation will require a new recloser at the substation. Replace switch PD.160-A with a gang switch. Remove recloser PD.3372. Open section PL.11553 from PL.30854 and close switch PD.160-A. (See RUS CODES 501 and 603-01)

Alternatives: A load transfer to Mt. Sterling is not possible due to backbone conductor size limitations, and it would transfer a critical load to the end of a long line.

Clay City – Circuit 2

- **RUS CODE - 372** **$163,900 in LL1**
- **PROJECT NAME – Snow Creek-1/0**

Description: Multi-phase with three-phase 1/0 ACSR from section PL.15497 to section PL.11743 for approximately 8,100 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.8180	A	B
PL.50358	A	C
PL.15620	A	C
PL.50359	A	B
PL.33026	C	A
PL.15960	A	B
PL.15622	B	A
PL.51611	B	A

The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Clay City Circuit 2 were loaded up to 70 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing and tap transfers.

Sectionalizing and Regulation: Add (2) 70V4E at recloser PD.3575. Remove regulator RG.22. (See RUS CODES 603-02 and 604-07)

Alternatives: Load transfers would impose a similar condition on the available ties.

Clay City – Circuit 4

- **RUS CODE - 379** **$140,600 in LL3**
- **PROJECT NAME – Highway 11-336**

Description: Reconductor and multi-phase with three-phase 336ACSR from line section PL.52126 to PL.12959 for approximately 5,200 feet. The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Clay City Circuit 4 were loaded up to 58 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing.

Sectionalizing: Relocate recloser PD.3369 from line section PL.19923 to the source end of section PL.53038. (See RUS CODE 603-03)

Alternatives: No alternative available

Frenchburg – Circuit 3

- **RUS CODE - 380** **$184,800 in LL1**
- **PROJECT NAME – Highway 36 @ Suiters Branch-336**

Description: Reconductor from line section PL.29091 to PL.19753 and from line section PL.19206 to PL.53851 with three-phase 336ACSR for approximately 7,300 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.55636	AC	AB
PL.55654	A	B
PL.47088	B	C
0332115	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Frenchburg Circuit 3 were loaded up to 85% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 58%. Also, Frenchburg Circuit 3 is a tie to an adjacent substation, and this project strengthens the tie for contingency switching.

Regulation: Relocate regulator RG.12 from line section PL.55682 to the load end of line section PL.21376 due to loading. (See RUS CODE 604-01)

Alternatives: A load transfer load to Jeffersonville would overload the backbone circuit.

Hardwick's Creek – Circuit 1

- **RUS CODE - 373** **$172,500 in LL1**
- **PROJECT NAME – Frames Branch-1/0**

Description: Multi-phase with three-phase 1/0 ACSR from section PL.53477 to section PL.12797 for approximately 8,500 feet. Backfeed section PL.32827 to OH20 and open between line sections PL.8208 and PL.8267. Transfer the following single-phase taps:

Element Name	From	To
PL.26085	C	A
PL.15339	B	A
PL.34909	C	B
PL.26690	A	C
PL.15233	C	A
PL.51661	A	B
PL.20140	C	B
PL.34903	C	B
PL.15076	A	C
075452	C	B
PL.26741	C	B
076516	B	C

The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Hardwicks Creek Circuit 1 were loaded up to 83 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing and tap transfers.

Sectionalizing: Replace recloser PD.8765 with a 70V4E. Relocate recloser PD.3440 from section PL.14429 to the source end of line section PL.26085. Add (2) 70V4E at recloser PD.3630. (See RUS CODE 603-04)

Alternatives: No alternatives available

Hunt – Circuit 3

- **RUS CODE - 374** **$122,100 in LL1**
- **PROJECT NAME – Drowning Creek-1/0**

Description: Multi-phase and reconductor with 3-ph 1/0 ACSR from section PL.27792 to section PL.16349 for approximately 6,000 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.37917	A	B
PL.5714	A	C
PL.5715	A	B
PL.16089	B	C
PL.18672	B	C

The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Hunt Circuit 3 were loaded up to 67 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing and tap transfers.

Sectionalizing: Replace recloser PD.3326 with (3) 50V4E to relieve loading. (See RUS CODE 603-05)

Alternatives: No alternative available.

Hunt – Circuit 3

- **RUS CODE - 375** **$73,200 in LL2**
- **PROJECT NAME – Flint Rd.-1/0**

Description: Multi-phase and reconductor with three-phase 1/0 ACSR from section PL.20386 to section PL.9336 for approximately 3,500 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.15114	C	B
PL.21057	C	B
PL.9330	C	A

The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Hunt Circuit 3 were loaded up to 59 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing and tap transfers.

Sectionalizing: Add (2) 50V4E to recloser PD.3327. (See RUS CODE 603-06)

Alternatives: No alternative available

Mt. Sterling – Circuit 3

- **RUS CODE - 381** **$149,700 in LL2**
- **PROJECT NAME – Goffs Corner-336**

Description: Multi-phase and reconductor from line section PL.16469 to section PL.10631 with three-phase 336ACSR for approximately 5,700 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.7956	B	C
PL.16480	B	A
PL.16065	C	B
PL.50797	C	B
PL.18568	A	B
065943	C	A

The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Mt Sterling Circuit 3 were loaded up to 59 A. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing. Also, the project is strengthening a potential tie to Trapp Substation.

Sectionalizing: Replace recloser PD.3347 with 3-ph VWVE#1, and relocate the existing (3) 50L's from line section PL.17902 to replace switch PD.2142 at the load end of section PL.16469. Remove recloser PD.3359 at the load end of section PL.17984 to relieve equipment loading. (See RUS CODE 603-08)

Alternatives: No alternative available.

Mt. Sterling – Circuit 3

- **RUS funds are not requested** **LL1**

Description: Transfer the following single-phase taps:

Element Name	From	To
PL.14234	C	A
PL.52960	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Mt. Sterling Circuit 3 were loaded up to 52% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 32%.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

Reid Village - Circuit 2

- **RUS CODE- 382** **$88,400 in LL1**
- **PROJECT NAME – Prewitt Pike-336**

Description: Reconductor from line section PL.29149 to PL.7556 with three-phase 336ACSR for approximately 3,500 feet. Transfer the following single-phase taps:

Element Name	From	To
PD.3667-A	A	B
PL.50607	A	C
PL.6754	B	C

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Reid Village circuit 2 were loaded up to 68% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 35%. Reid Village Circuit 2 is a tie to an adjacent substation, and this project strengthens the tie for contingency switching.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: Alternative is to transfer load to Mt. Sterling, but it would increase the exposure for reliability issues due to the increased distance (~3miles) from the substation.

Sideview – Circuit 3

- **RUS funds are not requested** **LL1**

Description: Transfer load from Sideview Circuit 3 by opening from line section PL.12078 and closing switch PD.6882-A to Reid Village Circuit 1. Transfer the following single-phase taps:

Element Name	From	To
PL.46428	C	B
PL.51429	C	B
PL.46388	B	A
PL.51144	C	A
PL.42780	B	A
PL.28326	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Sideview Circuit 3 were loaded up to 68% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 29%.

Regulation: Add (3) single-phase regulators at the load end of PL.12307. (See RUS CODE 604-05)

Alternatives: No alternative available.

Stanton – Circuit 3

- **RUS funds are not requested** **LL1**

Description: Transfer the following single-phase taps:

Element Name	From	To
PL.39561	C	B
PL.16260	C	B
PL.46019	C	A
PL.13275	A	B

The project is recommended due to low voltage, less than 118 V, in summer peak loading conditions. Before improvements, voltage on Stanton Circuit 3 was measured as low as 114.9 V by the end of the work plan. With the recommended improvements, the voltage was improved to 118 V.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

Stanton – Circuit 4

- **RUS CODE – 367 Carry-Over** **$90,600 in LL4**
- **PROJECT NAME – Lower Paint Creek**

Description: Reconductor and multi-phase section PL.34830 up-line to section PL.17519 from single-phase 4 ACSR to three-phase 336 ACSR for approximately 3,200 feet. Transfer the single-phase taps at sections PL.27294 and PL.38800 to C-phase. All remaining customers and taps on the new three-phase line should be transferred from B-phase to A-phase. The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Also, it is a possible tie to Clay City Substation. Before improvements, single-phase sections on Stanton 4 were loaded up to 66 A. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing and tap transfers.

Sectionalizing: Add (2) single-phase 70 V4E reclosers to the existing single-phase recloser at PD.3626. (See RUS Code 603-15)

Alternatives: Load transfers would impose a similar condition on the available tie circuits; therefore, no other options are available to reduce the loading on the tap. The proposed improvements were selected as the least cost option for the identified deficiencies.

Stone Rd. – Circuit 1

- **RUS CODE - 377** **$129,800 in LL1**
- **PROJECT NAME – Stone Rd.-1/0**

Description: Multi-phase and reconductor from line section PL.11645 to PL.11650 for approximately 6,400 feet from single-phase 4 ACSR to three-phase 1/0 ACSR. Open switch PD.302 from Circuit 1 and back-feed at section PL.11644. The project is recommended to balance load on the new Stone Rd Substation Circuit 2. Transfer the following single-phase taps:

Element Name	From	To
PL.11422	C	B
PL.11421	C	A

Regulation: Remove regulators RG.38 and REG13. (See RUS CODE 604-06)

Alternatives: Without the Stone Rd. Substation, over 6 miles of single-phase distribution would require multi-phasing to address single-phase loading issues in the area. Stone Rd. Substation was selected in the 2010 Long Range Plan, and is detailed in Appendix B of this report.

Treehaven – Circuit 2

- **RUS funds are not requested** **LL1**

Description: Transfer the following single-phase tap:

Element Name	From	To
PL.25564	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Treehaven circuit 2 were loaded up to 57% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 53%.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

Van Meter – Circuit 3

- **RUS CODE - 383** **$332,100 in LL1**
- **PROJECT NAME – Clintonville-336**

Description: Reconductor from PL.9238 to PL.19628 to 336 ACSR for approximately 13,100 feet. Transfer the following single-phase taps:

Element Name	From	To
PL.18431	C	B
PL.55721	A	B
PL.30802	A	B
PL.10036	C	B
PL.9836	C	B

The project is recommended to relieve conductor loading greater than 50% in summer peak loading conditions. Before improvements, sections on Van Meter Circuit 3 were loaded up to 78% of capacity by the end of the work plan. With the recommended improvements, the loading was reduced to 26%.

Regulation: Add a 219 A regulator at the load end of PL.9122. Remove RG.35 at the load end of PL.50390 due to loading issues. (See RUS CODE 604-03)

Alternatives: No alternative available.

Van Meter – Circuit 3

- **RUS funds are not requested** **LL1**

Description: Transfer load from Van Meter Circuit 3 to Sideview Circuit 4 by opening switch PD.292 and closing switch PD.8181, and transfer line sections PL.10340 to PL.42920 from B to A phase. The project is recommended to relieve single-phase loading greater than 56 A in winter peak loading conditions. Before improvements, single-phase sections on Van Meter Circuit 3 were loaded up to 65 A by the end of the work plan. With the recommended improvements, the single-phase loading issue was alleviated through multi-phasing.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

Sideview – Circuit 4

- **RUS funds are not requested** **LL1**

Description: Transfer the following single-phase tap:

Element Name	From	To
PL.10394	B	C
PL.27773	B	C
PL.42586	B	A
PL.15656	C	B
PL.55362	C	A
PL.25695	C	A
481226	B	C
PL.18540	C	B

The project is recommended due to low voltage, less than 118 V, in winter peak loading conditions. Before improvements, voltage on Sideview Circuit 4 was measured as low as 114.9 V by the end of the work plan. With the recommended improvements, the voltage was improved to 119 V.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

Blevins Valley– Circuit 2

- **RUS funds are not requested** **LL1**

Description: Transfer the following single-phase tap:

Element Name	From	To
PL.112	C	B
PL.12231	AC	AB
PL.10666	B	A
PL.42343	B	A

The project is recommended due to low voltage, less than 118 V, in winter peak loading conditions. Before improvements, voltage on Blevins Valley Circuit 2 was measured as low as 115.2 V by the end of the work plan. With the recommended improvements, the voltage was improved to 119.3 V.

Sectionalizing: Device coordination was reviewed based on the recommended changes, and no improvements are required.

Alternatives: No alternative available.

2.9 Sectionalizing Equipment

Specific locations for sectionalizing equipment were identified in this report. For the 2010 - 2014 CWP period, the following recloser recommendations are as follows. The cost was inflated by 3.5% per year.

Clay City -Circuit 1

- **RUS CODE – 603-01** **$7,500 in LL1**

Description: Replace switch PD.160-A with a gang switch. Remove recloser PD.3372. (See RUS CODE –378)

Clay City – Circuit 2

- **RUS CODE - 603-02** **$11,800 in LL1**

Description: Add (2) single phase 70V4E at recloser PD.3575. (See RUS CODE –372)

Clay City – Circuit 4

- **RUS CODE – 603-03** **$2,300 in LL3**

Description: Relocate recloser PD.3369 from line section PL.19923 to the source end of section PL.53038. (See RUS CODE -379)

Hardwick's Creek -Circuit 1

- **RUS CODE – 603-04** **$20,900 in LL1**

Description: Replace recloser PD.8765 with a 70V4E. Relocate recloser PD.3440 from section PL.14429 to the source end of line section PL.26085. Add (2) 70V4E at recloser PD.3630. (See RUS CODE - 373)

Hunt – Circuit 3

- **RUS CODE – 603-05** **$12,100 in LL1**

Description: Replace recloser PD.3326 with (3) 50V4E to relieve loading. (See RUS CODE –374)

Hunt - Circuit 3

- **RUS CODE – 603-06** **$12,200 in LL2**

Description: Add (2) 50V4E to recloser PD.3327. (See RUS CODE – 375)

Mt. Sterling – Circuit 3

- **RUS CODE – 603-08** **$41,500 in LL2**

Description: Replace recloser PD.3347 with three-phase VWVE#1, and relocate the existing (3) 50L's from line section PL.17902 to replace switch PD.2142 at the load end of section PL.16469. Remove recloser PD.3359 at the load end of section PL.17984 to relieve equipment loading. (See RUS CODE –381)

Stanton – Circuit 4

- **RUS CODE – 603-15 Carry over** **$13,100 in LL4**

Description: Add (2) single-phase 70V4E reclosers to the existing single-phase recloser at PD.3626. (See RUS CODE – 367)

2.10 Line Regulators

Specific locations for line regulators were identified to correct voltage drop problems as an alternative solution when switching was not feasible or reconductoring was more expensive and not necessary due to lightly loaded circuits. The total estimated cost was inflated 3.5% per year to the recommended year of the 2010 - 2014 CWP.

Frenchburg – Circuit 3

- **RUS CODE – 604-01** **$4,700 in LL1**

Description: Relocate regulator RG.12 from line section PL.55682 to the load end of line section PL.21376 due to loading. (See RUS CODE – 380)

Frenchburg – Circuit 1

- **RUS CODE – 604-02** **$4,700 in LL1**

Description: Relocate regulator RG.11 from line section PL.37744 to the load end of line section PL.9718 due to low voltage issue.

Van Meter – Circuit 3

- **RUS CODE – 604-03** **$49,900 in LL1**

Description: Add a 219 A regulator at the load end of PL.9122. Remove RG.35 at the load end of PL.50390 due to loading issues. (See RUS CODE – 383)

High Rock – Circuit 1

- **RUS CODE – 604-04** **$10,700 in LL1**

Description: Add a single-phase 100 A regulator at the load end of line section PL.28129 to relieve loading on regulator RG.28.

Reid Village – Circuit 1

- **RUS CODE – 604-05** **$32,100 in LL1**

Description: Add (3) single-phase 100 A regulators at the load end of line section PL.12307. (See Sideview -Circuit 3)

Stone Rd. – Circuit 1

- **RUS CODE – 604-06** **$6,000 in LL1**

Description: Remove regulators RG.38 and REG13 at the load end of PL.50823 and PL.15744, respectively. (See RUS CODE 377)

Clay City – Circuit 2

- **RUS CODE – 604-07** **$3,000 in LL1**

Description: Remove regulator RG.22 at the load end of PL.6947. (See RUS CODE 372)

2.11 Conductor Replacement

For the 2010 - 2014 CWP period, specific locations for conductor replacement were not identified in this report. Clark Energy plans to reconductor approximately 10 miles per year on the system to improve reliability and replace aging conductors. The cost was inflated by 3.5% per year.

System Wide

- **RUS CODE – 608** **$993,400 over LL1-LL4**

Description: Reconductor approximately 10 miles of single-phase conductors per year on the system to improve reliability and replace aging conductors. The amount of single-phase conductors with over 20 Amps of projected load to be replaced is approximately 120 miles of 4 ACSR. Costs for conductor replacement are based upon the assumption that lines will be reconductored with #1/0 ACSR.

- **RUS CODE – 611** **$526,400 in LL1**
- **PROJECT NAME – Hwy 801**

Description: The project area is located in the Daniel Boone National Forest near Highway 801 between Scott Creek Forestry Road and Johnson Hollow Road. Clark Energy is proposing to replace the approximately three (3) miles of existing three-phase overhead power lines with approximately two (2) miles of three-phase underground power lines along the right of way (ROW) of Highway 801. By using the ROW on the existing Highway 801, Clark Energy will be able to better serve its customers, as well as cause little to no additional negative impact on the surrounding protected National Forest. Converting the overhead power lines to underground power lines through directional boring will eliminate the problem of trees and limbs damaging the lines during storms and mitigate the costs associated with the constant repair work in the future. The Gateway Regional Hazard Mitigation Plan, Action Item 1.2.1, calls for local government to "work with utility companies to trim trees and remove debris from power lines." The intent of this objective is to reduce the number of power outages caused by storm related damage. Cost estimate details are given in Exhibit 3.

2.12 Miscellaneous Replacements

- **RUS CODE – 607** **$304,800 over LL1-LL4**

Description: Miscellaneous Replacements, includes all costs associated with replacement of plant items such as guys, anchors, crossarms, switches, insulator strings, etc. where pole change out due to condition of pole is not the predominant cost involved.

Section 3
ECONOMIC CONDUCTOR SELECTION

The data contained in this section details the assumptions which were used in the economic analysis of alternatives and economic conductor sections of this report.

3.1 Interest Rates

To determine a real interest rate, historical interest rates were reviewed relative to the rate of inflation. Historically, prime lending rates have been one to three percent greater than inflation. A conservative real interest rate of 1.5% was assumed, and when combined with a 3.5% inflation rate, the discount rate for economic analysis was 5.0%.

3.2 Fixed Annual Charge Rates

Fixed annual charge rates were developed based on Clark Energy's 2006-2008 operation and maintenance expense of the installed plant and an interest rate as previously developed. The fixed annual charge rates used are summarized in Table 3-1.

Table 3-1
Summary of Assumed Fixed Annual Charge Rates

Item	Plant (1)		
	Transmission	Substation	Distribution
Cost of Capital	5.00%	5.00%	5.00%
Depreciation	2.50%	2.00%	3.00%
Operation and Maintenance (2)	3.00%	2.00%	4.10%
Taxes	0.05%	0.05%	0.05%
Insurance	0.04%	0.04%	0.04%
TOTAL	10.59%	9.09%	12.19%

Notes:
(1) Rates expressed as a percent of original installed cost.
(2) Transmission and substation O & M cost are assumed values.

3.3 Cost of Power

The cost of power in 2008 was $0.0637 per kWh, based on information provided by Clark Energy. It is anticipated that trends for the current market will increase power costs during the planning period; therefore, power costs were assumed to increase at a rate of 5.0%.

3.4 Cost of Losses

The cost of losses was calculated based on the wholesale power cost of 0.067 mills/kWh. The wholesale power costs were obtained from the 2008 Clark Energy Form 7 data. The calculated cost of losses was based on an average of the 2006, 2007 and 2008 monthly billing demands and an average annual load factor of 42.55%. The cost of losses to carry one kW of loss at peak is $122.91. The calculation is given in Exhibit 4.

3.5 Economic Conductor Selection

Economic conductor selection includes the consideration of initial construction costs and the associated losses of the selected conductors. For two alternative conductors compared, there is generally a kW load at which the fixed costs associated with the construction, plus the variable costs related to line losses, are equal for the two alternatives. For loads less than the equal cost load, the smaller conductor should be selected, and for loads greater than such load, the larger conductor would be selected. There are many choices of conductor sizes, but as part of system operation, standard conductor sizes for overhead construction of #2 ACSR, #1/0 ACSR, 336 ACSR, and 795 ACSR have been selected by Clark Energy.

Since a distribution line is used for many years, economic conductor selection should include the consideration of the initial load, load growth, cost of losses, increases in power cost, the annual fixed cost, and the present worth of the dollars spent.

The load on the distribution line considered was expressed as the current annual peak load and was assumed to grow over the life cycle analyzed. The cost of power was assumed to remain constant and a thirty-year present-worth factor was developed for the cost of losses and for the annual fixed cost.

Two basic conditions arise as alternatives are compared. The first, and most often encountered alternative, is the timing of the conversion of an existing distribution line. The question is simply a comparison of which is more economical for the next year. Thus, based on economics alone, the existing distribution line should remain as long as the annual cost of the losses on the existing line is less than the annual cost of the losses, plus fixed costs on the new line. Generally, voltage-drop problems require conversion prior to economics.

The second alternative arises when a new line is to be constructed or an existing line must be changed for reasons other than economic conductor selection. Such conditions include voltage drop, system changes, and reliability. Economic conductor selection analyses were performed and a summary for new construction and change-out was prepared.

General guidelines were developed based on the following assumptions.

- Compound annual load growth 2.54%
- Annual cost of peak kW losses \$122.91/kW
- Compound annual power cost increase 5.0%
- Fixed cost factor 12.19%
- Present worth discount factor 5.0%
- Distribution line cost estimates in Table 1-2

3.5.1 24.9/14.4 kV Operating Voltage

The following general guidelines were developed based upon the analysis described previously for overhead conductors at an operating voltage of 24.9/14.4 kV.

New single-phase distribution lines should generally be constructed with #1/0 ACSR if the load on the line will potentially grow to require conversion to three-phase. If the load will not grow requiring conversion to three-phase, #2 ACSR is adequate for single-phase construction for loads less than 800 kW.

The single-phase #1/0 ACSR lines should be converted to three-phase #1/0 ACSR based upon operating conditions and voltage-drop.

Existing three-phase distribution lines should be reconductored based on the following:

- For loads less than 1,300 kW: 2 ACSR
- For loads greater than 1,300 kW and less than 2,250 kW: 1/0 ACSR
- For loads greater than 2,250 kW and less than 6,900 kW: 336 ACSR
- For loads greater than 6,900 kW: 795 ACSR

New three-phase 24.9 kV distribution lines should be constructed with the following conductors at the initial load given as follows:

- For loads less than 1,300 kW: 2 ACSR
- For loads greater than 1,300 kW and less than 2,250 kW: 1/0 ACSR
- For loads greater than 2,250 kW and less than 6,900 kW: 336 ACSR
- For loads greater than 6,900 kW: 795 ACSR

Economic conductor selection curves for overhead conductors are graphically presented in Figures 3-1 through 3-4. The economic conductor selection curves and guides should be updated periodically based on changes in construction cost, power cost, or fixed operating cost.

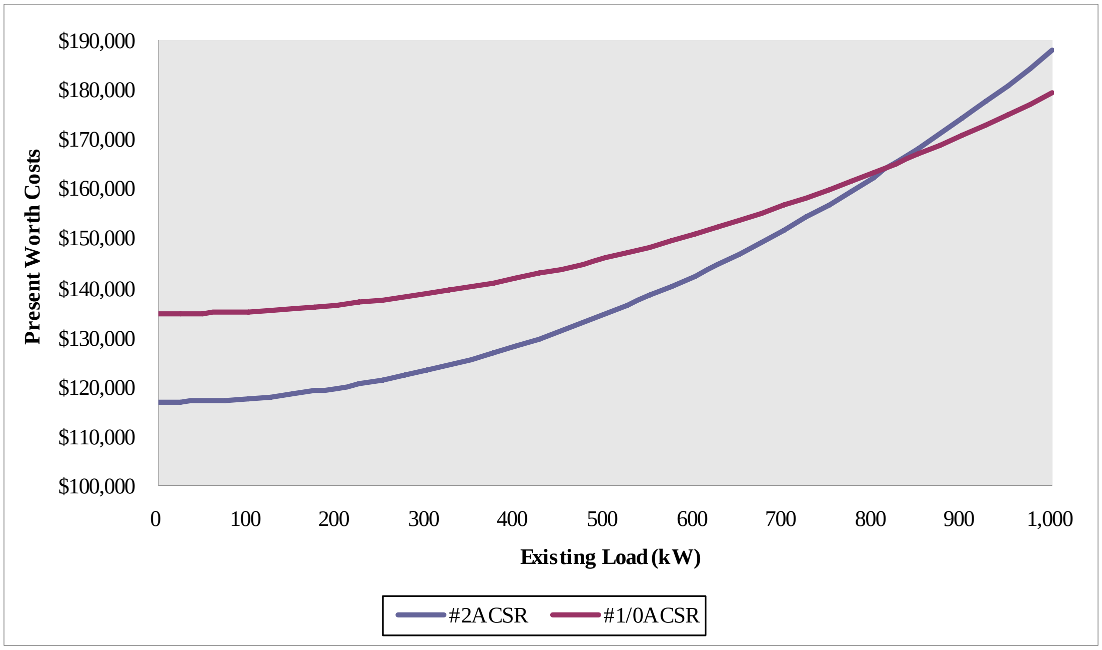

Figure 3-1: Single-Phase Construction 14.4 kV

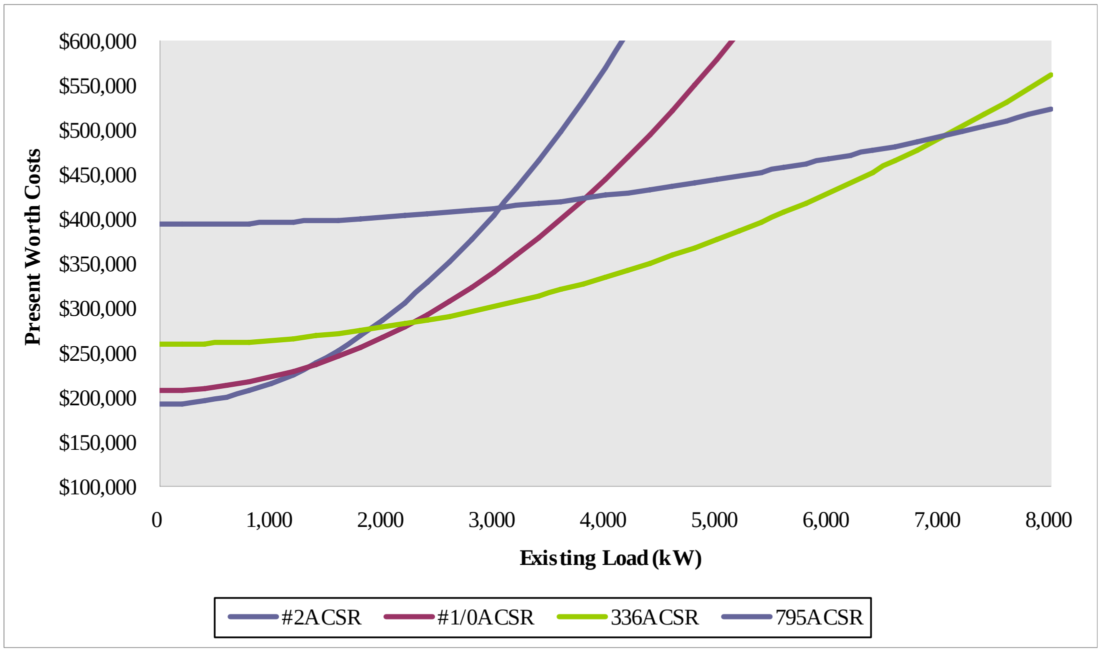

Figure 3-2: Three-Phase Construction 24.9 kV

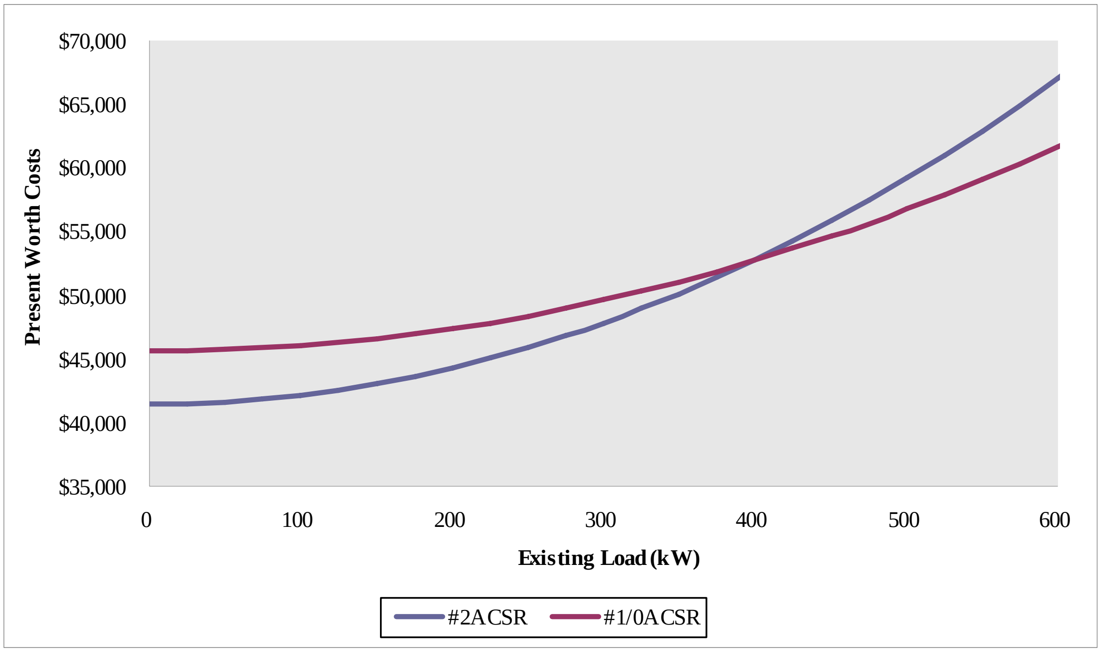

Figure 3-3: Single-Phase Reconductor 14.4 kV

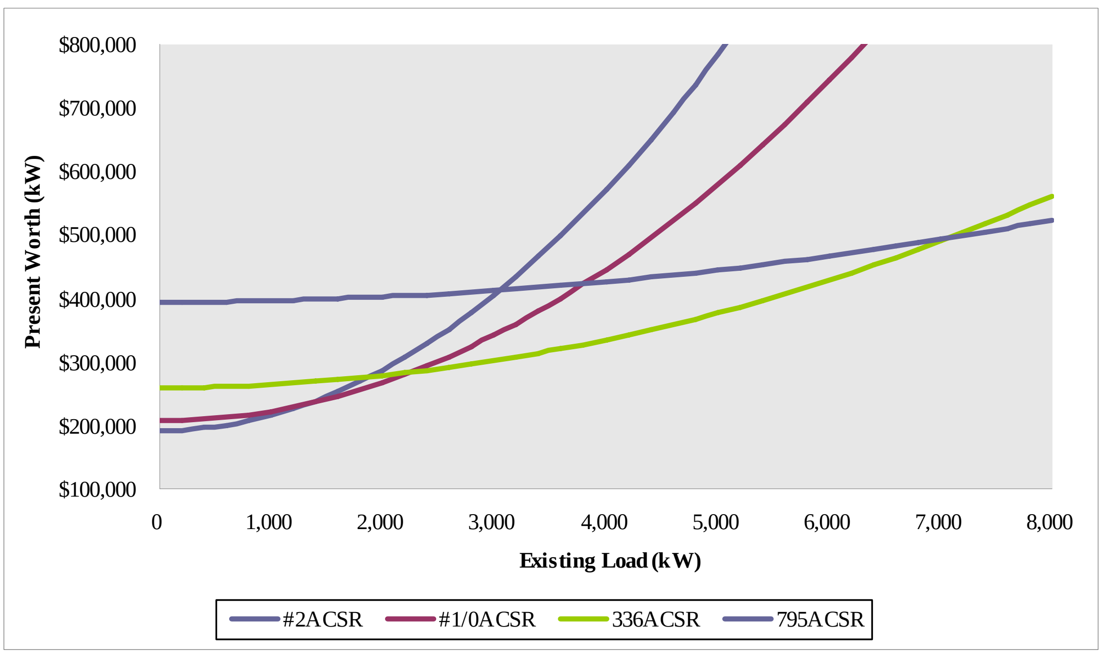

Figure 3-4: Three-Phase Reconductor 24.9 kV

3.5.2 12.47/7.2 kV Operating Voltage

The following general guidelines were developed based upon the analysis described previously for overhead conductors at an operating voltage of 12.47/7.2 kV.

New single-phase distribution lines should generally be constructed with #1/0 ACSR if the load on the line will potentially grow to require conversion to three-phase. If the load will not grow requiring conversion to three-phase, #2 ACSR is adequate for single-phase construction for loads less than 400 kW.

The single-phase #1/0 ACSR lines should be converted to three-phase #1/0 ACSR based upon operating conditions and voltage-drop.

Existing three-phase distribution lines should be reconductored based on the following:

- For loads less than 650 kW: 2 ACSR
- For loads greater than 650 kW and less than 1,100 kW: 1/0 ACSR
- For loads greater than 1,100 kW and less than 3,500 kW: 336 ACSR
- For loads greater than 3,500 kW: 795 ACSR

New three-phase 12.47 kV distribution lines should be constructed with the following conductors at the initial load given as follows:

- For loads less than 650 kW: 2 ACSR
- For loads greater than 650 kW and less than 1,100 kW: 1/0 ACSR
- For loads greater than 1,100 kW and less than 3,450 kW: 336 ACSR
- For loads greater than 3,450 kW: 795 ACSR

Economic conductor selection curves for overhead conductors are graphically presented in Figures 3-5 through 3-8. The economic conductor selection curves and guides should be updated periodically based on changes in construction cost, power cost, or fixed operating cost.

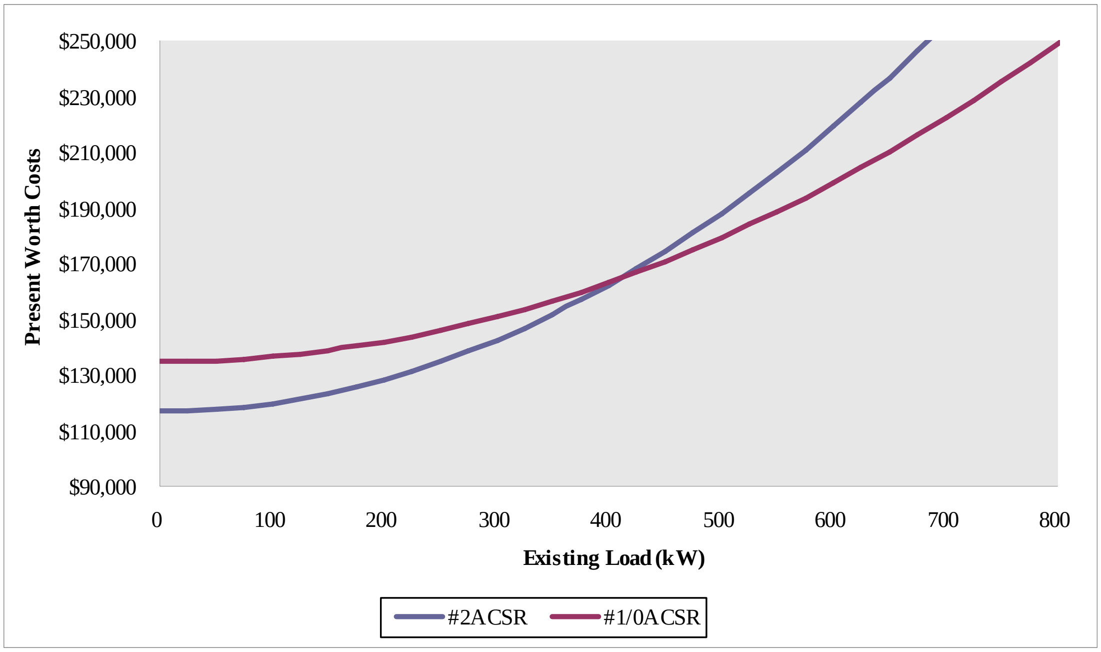

Figure 3-5: Single-Phase Construction 7.2 kV

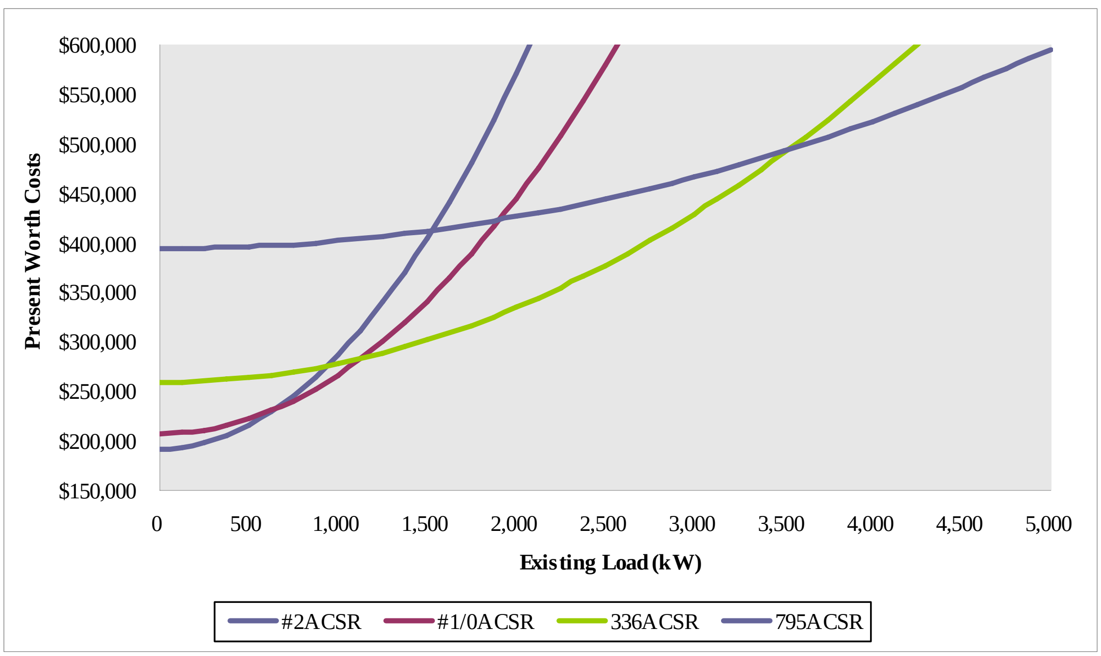

Figure 3-6: Three-Phase Construction 12.47 kV

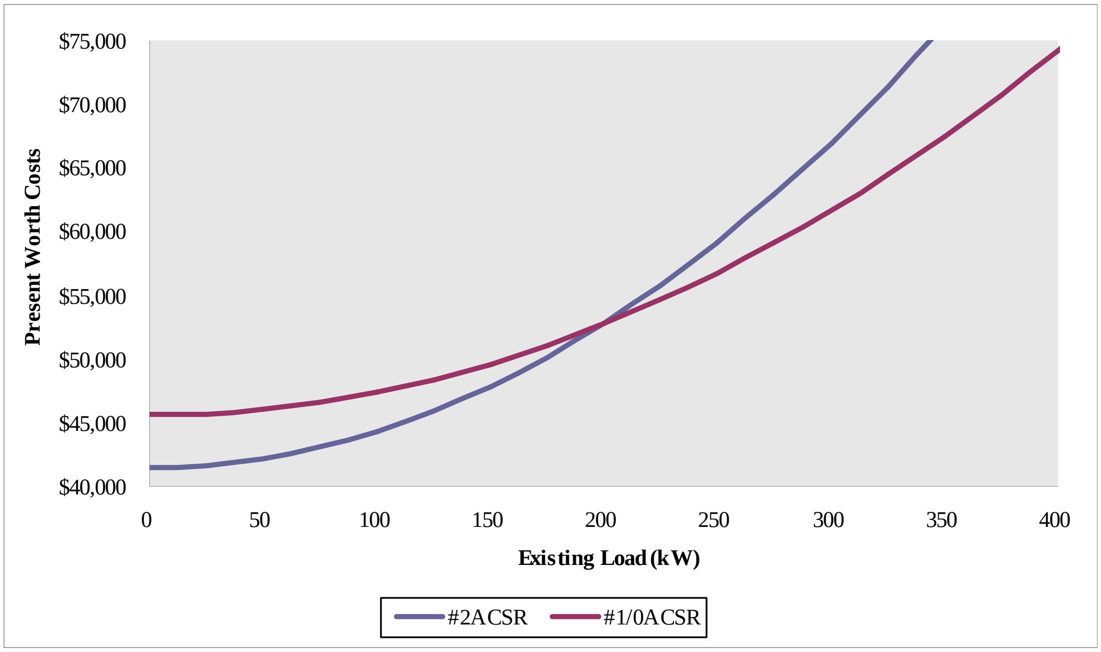

Figure 3-7: Single-Phase Reconductor 7.2 kV

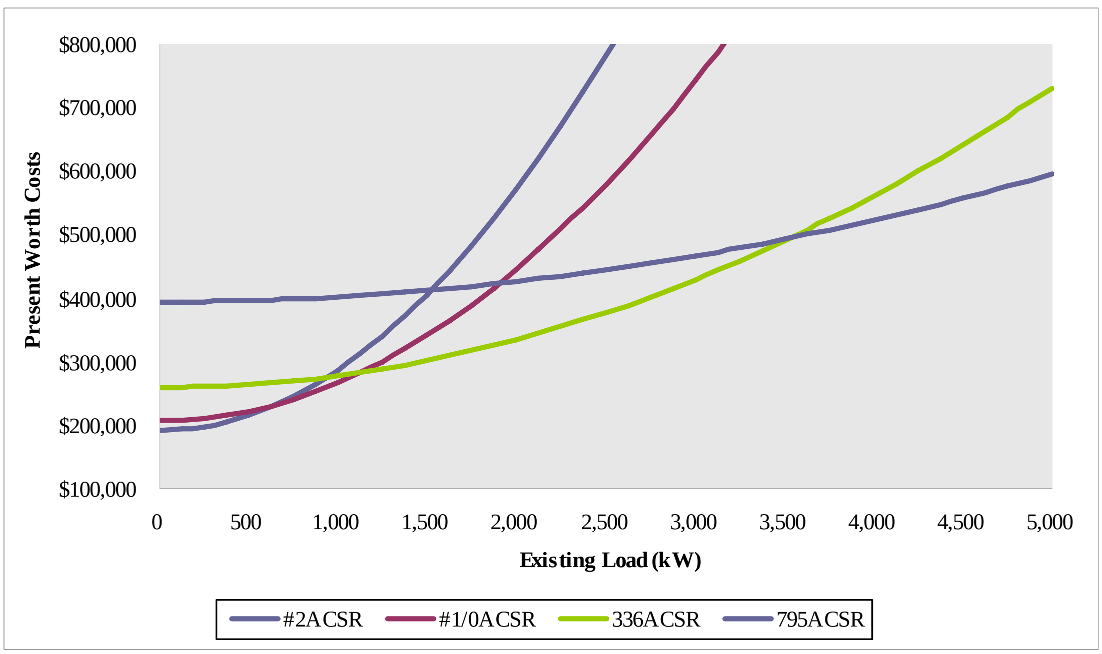

Figure 3-8: Three-Phase Reconductor 12.47 kV

Exhibit 1
Status of Previous CWP Projects

Clark Energy Cooperative, Inc.
2006 - 2010 Construction Work Plan

Status of Previous CWP Projects					
CFR Code	Substation	Description	Est. WP Miles	Est. cost	Status
324	Clay City - Circuit 2	Hwy 15\Hwy 82	1.65	$140,600	Completed
342	Clay City - Circuit 2	New Clay City Circuit	1.34	$127,500	Completed
344	Clay City - Circuits 1 & 2	Clay City Double Circuit	0.96	$95,400	Completed
345	Clay City - Circuit 4	Hwy 11	0.46	$40,700	Completed
347	Frenchburg - Circuit 1	Hwy 36	0.61	$54,800	Completed
348	Frenchburg - Circuit 2	Amos Ridge	1.22	$94,900	Completed
374	Frenchburg - Circuit 3	Indian Creek	1.12	$84,100	Completed
349	Frenchburg - Circuit 3	Downtown Frenchburg	1.38	$117,800	Completed
350	Frenchburg - Circuit 4	Leatherwood	4.94	$44,000	Cancelled
352	Hardwick's Creek -Circuit 2	Lone Oak	0.97	$67,700	Completed
354	Hinkston - Circuit 2	Van Thompson	0.81	$59,500	Completed
355	Hinkston - Circuit 3	Hwy 60/Mtn View	1.53	$122,500	Completed
305	Miller Hunt - Circuit 2	Hwy 89/Ruckerville	2.56	$186,900	Completed
358	Mt. Sterling - Circuit 2	Nest Egg	0.36	$27,100	Completed
360	Reid Village - Circuit 1	Hwy 60/Sewell Shop	2.39	$203,300	Completed
362	Sideview - Circuit 1	Rock Ridge	2.72	$204,500	Cancelled
364	Sideview - Circuit 4	Hwy 627	2.67	$201,100	Completed
365	Stanton - Circuit 2	Hwy 15\Elkings Street	0.19	$16,100	Completed
366	Stanton - Circuit 3	Hatton Creek	0.38	$32,300	Completed
367	Stanton - Circuit 4	Lower Paint Creek	0.61	$53,200	Carry-over
368	Stanton - Circuit 4	New Stanton Circuit	0.72	$122,600	Completed
369	Trapp - Circuit 2	Log Lick	0.31	$23,500	Completed
371	Union City - Circuit 2	Charlie Norris Road	1.99	$145,400	Completed
704-1	SCADA System Stage 1			$25,000	Completed
704-2	SCADA System Stage 2			$250,000	Carry-over
		TOTAL		$2,540,500	

Exhibit 2
Substation and Feeder Forecast

Clark Energy Cooperative, Inc.
(Summer) Substation and Feeder Load Forecast

	TOTAL		RELATIVE	2007	PROJECTED LOADS (MW)																				COMP.
SUBSTATION /	CAPACITY	LIMITING	GROWTH	PEAK	LL1	LL2	LL3	LL4	LL5	LL6	LL7	LL8	LL9	LL10	LL11	LL12	LL13	LL14	LL15	LL16	LL17	LL18	LL19	LL20	ANNUAL
FEEDER NAME	(MVA)	ELEMENT	FACTOR	(MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	2.11%
BLEVINS VALLEY	4.4	Transformer	0.75	2.93	3.15	3.19	3.24	3.28	3.35	3.42	3.49	3.56	3.61	3.65	3.70	3.74	3.78	3.82	3.87	3.99	4.11	4.23	4.36	4.48	1.87%
BLEVAL1			1.00	1.10	1.18	1.20	1.21	1.23	1.25	1.28	1.31	1.33	1.35	1.36	1.38	1.40	1.42	1.43	1.45	1.49	1.54	1.58	1.63	1.68	1.87%
BLEVAL2			1.00	1.51	1.62	1.64	1.67	1.69	1.72	1.76	1.80	1.83	1.86	1.88	1.90	1.93	1.95	1.97	1.99	2.05	2.12	2.18	2.24	2.31	1.87%
BLEVAL3			1.00	0.33	0.35	0.35	0.36	0.36	0.37	0.38	0.39	0.39	0.40	0.40	0.41	0.41	0.42	0.42	0.43	0.44	0.46	0.47	0.48	0.50	1.87%
Total Feeder Load				2.93	3.15	3.19	3.24	3.28	3.35	3.42	3.49	3.56	3.61	3.65	3.70	3.74	3.78	3.82	3.87	3.99	4.11	4.23	4.36	4.48	-----
Substation Growth Factors					0.075	0.014	0.014	0.012	0.022	0.021	0.021	0.020	0.013	0.010	0.014	0.012	0.011	0.010	0.014	0.030	0.030	0.030	0.029	0.029	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
BOWEN	5.5	Transformer	0.10	3.95	3.98	3.99	4.00	4.01	4.02	4.03	4.04	4.05	4.06	4.06	4.07	4.08	4.08	4.09	4.10	4.11	4.13	4.15	4.16	4.18	0.25%
BOWEN1			1.00	1.50	1.52	1.52	1.52	1.53	1.53	1.53	1.54	1.54	1.55	1.55	1.55	1.55	1.56	1.56	1.56	1.57	1.57	1.58	1.59	1.59	0.25%
BOWEN2			1.00	1.46	1.48	1.48	1.48	1.49	1.49	1.50	1.50	1.50	1.51	1.51	1.51	1.51	1.52	1.52	1.52	1.53	1.53	1.54	1.54	1.55	0.25%
BOWEN3			1.00	0.98	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.03	1.03	1.04	0.25%
Total Feeder Load				3.95	3.98	3.99	4.00	4.01	4.02	4.03	4.04	4.05	4.06	4.06	4.07	4.08	4.08	4.09	4.10	4.11	4.13	4.15	4.16	4.18	-----
Substation Growth Factors					0.010	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.002	0.001	0.002	0.002	0.001	0.001	0.002	0.004	0.004	0.004	0.004	0.004	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
CAVE RUN	1.8	Transformer	0.50	1.31	1.37	1.39	1.40	1.41	1.43	1.45	1.47	1.49	1.51	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.64	1.67	1.71	1.74	1.25%
CAVERUN1			1.00	0.80	0.84	0.85	0.86	0.86	0.88	0.89	0.90	0.91	0.92	0.93	0.94	0.94	0.95	0.96	0.97	0.99	1.01	1.03	1.05	1.07	1.25%
CAVERUN2			1.00	0.51	0.53	0.54	0.54	0.55	0.55	0.56	0.57	0.58	0.58	0.59	0.59	0.60	0.60	0.61	0.61	0.62	0.64	0.65	0.66	0.67	1.25%
Total Feeder Load				1.31	1.37	1.39	1.40	1.41	1.43	1.45	1.47	1.49	1.51	1.52	1.53	1.54	1.55	1.56	1.58	1.61	1.64	1.67	1.71	1.74	-----
Substation Growth Factors					0.051	0.009	0.009	0.008	0.015	0.014	0.014	0.013	0.009	0.007	0.009	0.008	0.007	0.007	0.009	0.020	0.020	0.020	0.020	0.020	-----
Substation Coincident Factor				100.08%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
CLAY CITY	13.6	Transformer	0.80	9.33	10.07	10.22	10.37	10.51	10.75	11.00	11.24	11.48	11.65	11.77	11.94	12.10	12.24	12.37	12.56	12.96	13.37	13.79	14.23	14.67	2.00%
CLAYCTY1			1.00	3.04	3.28	3.33	3.38	3.42	3.50	3.58	3.66	3.74	3.79	3.83	3.89	3.94	3.99	4.03	4.09	4.22	4.35	4.49	4.63	4.78	2.00%
CLAYCTY2			1.00	1.73	1.87	1.90	1.93	1.95	2.00	2.04	2.09	2.13	2.16	2.19	2.22	2.25	2.27	2.30	2.33	2.41	2.49	2.56	2.64	2.73	2.00%
CLAYCTY3			1.00	2.38	2.57	2.61	2.64	2.68	2.74	2.80	2.86	2.93	2.97	3.00	3.04	3.08	3.12	3.15	3.20	3.30	3.41	3.52	3.63	3.74	2.00%
CLAYCTY4			1.00	2.18	2.35	2.39	2.42	2.46	2.51	2.57	2.63	2.68	2.72	2.75	2.79	2.83	2.86	2.89	2.94	3.03	3.13	3.22	3.33	3.43	2.00%
Total Feeder Load				9.33	10.07	10.22	10.37	10.51	10.75	11.00	11.24	11.48	11.65	11.77	11.94	12.10	12.24	12.37	12.56	12.96	13.37	13.79	14.23	14.67	-----
Substation Growth Factors					0.080	0.015	0.014	0.013	0.023	0.023	0.022	0.022	0.014	0.011	0.015	0.013	0.012	0.011	0.015	0.032	0.032	0.032	0.031	0.031	-----
Substation Coincident Factor				99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
FRENCHBURG	13.6	Transformer	0.50	7.46	7.83	7.90	7.97	8.04	8.16	8.27	8.39	8.50	8.58	8.63	8.71	8.78	8.85	8.91	8.99	9.17	9.35	9.54	9.73	9.92	1.25%
FRNBURG1			1.00	1.10	1.15	1.16	1.17	1.18	1.20	1.22	1.24	1.25	1.26	1.27	1.28	1.29	1.30	1.31	1.32	1.35	1.38	1.40	1.43	1.46	1.25%
FRNBURG2			1.00	1.33	1.39	1.41	1.42	1.43	1.45	1.47	1.49	1.51	1.53	1.54	1.55	1.56	1.58	1.59	1.60	1.63	1.67	1.70	1.73	1.77	1.25%
FRNBURG3			1.00	3.46	3.63	3.66	3.69	3.72	3.78	3.83	3.88	3.94	3.97	4.00	4.04	4.07	4.10	4.13	4.16	4.25	4.33	4.42	4.50	4.59	1.25%
FRNBURG4			1.00	1.58	1.66	1.67	1.69	1.70	1.73	1.75	1.77	1.80	1.81	1.83	1.84	1.86	1.87	1.88	1.90	1.94	1.98	2.02	2.06	2.10	1.25%
Total Feeder Load				7.46	7.83	7.90	7.97	8.04	8.16	8.27	8.39	8.50	8.58	8.63	8.71	8.78	8.85	8.91	8.99	9.17	9.35	9.54	9.73	9.92	-----
Substation Growth Factors					0.049	0.009	0.009	0.008	0.015	0.014	0.014	0.013	0.009	0.007	0.009	0.008	0.007	0.007	0.009	0.020	0.020	0.020	0.020	0.020	-----
Substation Coincident Factor				99.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
Grayson Meter PT	0.1		0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00%
Grayson			1.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00%
Total Feeder Load				0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-----
Substation Growth Factors					0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HARDWICKS CREEK	13.6	Transformer	1.00	2.35	2.58	2.63	2.67	2.72	2.80	2.88	2.96	3.04	3.09	3.13	3.19	3.24	3.29	3.33	3.40	3.53	3.67	3.82	3.97	4.12	2.50%
HARDWICKS1			1.00	1.56	1.72	1.75	1.78	1.81	1.86	1.92	1.97	2.02	2.06	2.09	2.12	2.16	2.19	2.22	2.26	2.35	2.45	2.54	2.64	2.75	2.50%
HARDWICKS2			1.00	0.40	0.44	0.45	0.46	0.47	0.48	0.49	0.51	0.52	0.53	0.54	0.55	0.56	0.56	0.57	0.58	0.61	0.63	0.65	0.68	0.71	2.50%
HARDWICKS3			1.00	0.38	0.42	0.43	0.44	0.44	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.54	0.55	0.58	0.60	0.62	0.65	0.67	2.50%
Total Feeder Load				2.35	2.58	2.63	2.67	2.72	2.80	2.88	2.96	3.04	3.09	3.13	3.19	3.24	3.29	3.33	3.40	3.53	3.67	3.82	3.97	4.12	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Summer) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2007 PEAK (MW)	PROJECTED LOADS (MW) LL1 2010	LL2 2011	LL3 2012	LL4 2013	LL5 2014	LL6 2015	LL7 2016	LL8 2017	LL9 2018	LL10 2019	LL11 2020	LL12 2021	LL13 2022	LL14 2023	LL15 2024	LL16 2025	LL17 2026	LL18 2027	LL19 2028	LL20 2029	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	2.11%
HIGH ROCK	1.0	Transformer	0.50	0.56	0.58	0.59	0.60	0.60	0.61	0.62	0.63	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.67	0.68	0.70	0.71	0.73	0.74	1.25%
HIGHROCK1			1.00	0.56	0.58	0.59	0.60	0.60	0.61	0.62	0.63	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.67	0.68	0.70	0.71	0.73	0.74	1.25%
Total Feeder Load				0.56	0.58	0.59	0.60	0.60	0.61	0.62	0.63	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.67	0.68	0.70	0.71	0.73	0.74	-----
Substation Growth Factors					0.052	0.009	0.009	0.008	0.015	0.014	0.014	0.013	0.009	0.007	0.009	0.008	0.007	0.007	0.009	0.020	0.020	0.020	0.020	0.020	-----
Substation Coincident Factor				100.18%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HINKSTON	13.6	Transformer	1.00	3.52	3.87	3.95	4.02	4.08	4.20	4.32	4.44	4.56	4.64	4.71	4.79	4.87	4.94	5.01	5.10	5.31	5.52	5.73	5.96	6.19	2.50%
HINKSTON1			1.00	0.53	0.59	0.60	0.61	0.62	0.63	0.65	0.67	0.69	0.70	0.71	0.72	0.74	0.75	0.76	0.77	0.80	0.83	0.87	0.90	0.94	2.50%
HINKSTON2			1.00	1.09	1.20	1.22	1.24	1.26	1.30	1.34	1.37	1.41	1.43	1.45	1.48	1.50	1.53	1.55	1.58	1.64	1.70	1.77	1.84	1.91	2.50%
HINKSTON3			1.00	1.47	1.61	1.64	1.67	1.70	1.75	1.80	1.85	1.90	1.93	1.96	2.00	2.03	2.06	2.09	2.13	2.21	2.30	2.39	2.48	2.58	2.50%
HINKSTON4			1.00	0.44	0.48	0.49	0.50	0.50	0.52	0.53	0.55	0.56	0.57	0.58	0.59	0.60	0.61	0.62	0.63	0.65	0.68	0.71	0.73	0.76	2.50%
Total Feeder Load				3.53	3.87	3.95	4.02	4.08	4.20	4.32	4.44	4.56	4.64	4.71	4.79	4.87	4.94	5.01	5.10	5.31	5.52	5.73	5.96	6.19	-----
Substation Growth Factors					0.098	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				99.86%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HOPE	8.9	Fuse	1.00	4.43	4.87	4.96	5.05	5.14	5.29	5.44	5.59	5.74	5.84	5.92	6.03	6.12	6.21	6.30	6.42	6.67	6.94	7.21	7.49	7.79	2.50%
HOPE1			1.00	0.40	0.44	0.45	0.46	0.46	0.48	0.49	0.51	0.52	0.53	0.54	0.55	0.55	0.56	0.57	0.58	0.60	0.63	0.65	0.68	0.70	2.50%
HOPE2			1.00	1.22	1.34	1.37	1.39	1.41	1.45	1.50	1.54	1.58	1.61	1.63	1.66	1.68	1.71	1.73	1.77	1.84	1.91	1.98	2.06	2.14	2.50%
HOPE3			1.00	2.81	3.09	3.15	3.20	3.26	3.35	3.45	3.54	3.64	3.70	3.75	3.82	3.88	3.94	4.00	4.07	4.23	4.40	4.57	4.75	4.94	2.50%
Total Feeder Load				4.43	4.87	4.96	5.05	5.14	5.29	5.44	5.59	5.74	5.84	5.92	6.03	6.12	6.21	6.30	6.42	6.67	6.94	7.21	7.49	7.79	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HUNT	13.6	Transformer	1.00	6.22	6.84	6.97	7.09	7.21	7.42	7.63	7.84	8.06	8.20	8.31	8.46	8.60	8.72	8.84	9.01	9.37	9.74	10.12	10.52	10.93	2.50%
HUNT1			1.00	1.04	1.14	1.16	1.18	1.20	1.24	1.27	1.31	1.35	1.37	1.39	1.41	1.44	1.46	1.48	1.50	1.56	1.63	1.69	1.76	1.83	2.50%
HUNT2			1.00	0.33	0.36	0.37	0.38	0.38	0.39	0.40	0.41	0.43	0.43	0.44	0.45	0.45	0.46	0.47	0.48	0.50	0.52	0.54	0.56	0.58	2.50%
HUNT3			1.00	2.25	2.47	2.52	2.56	2.60	2.68	2.76	2.83	2.91	2.96	3.00	3.06	3.11	3.15	3.19	3.25	3.38	3.52	3.66	3.80	3.95	2.50%
HUNT4			1.00	2.61	2.87	2.92	2.97	3.02	3.11	3.20	3.29	3.37	3.43	3.48	3.54	3.60	3.65	3.70	3.77	3.92	4.08	4.24	4.41	4.58	2.50%
Total Feeder Load				6.22	6.84	6.97	7.09	7.21	7.42	7.63	7.84	8.06	8.20	8.31	8.46	8.60	8.72	8.84	9.01	9.37	9.74	10.12	10.52	10.93	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.02%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
JEFFERSONVILLE	11.1	Transformer	1.00	4.81	5.29	5.38	5.48	5.57	5.73	5.90	6.06	6.22	6.33	6.42	6.54	6.64	6.74	6.83	6.96	7.24	7.53	7.82	8.13	8.45	2.50%
JVILLE1			1.00	2.69	2.96	3.01	3.07	3.12	3.21	3.30	3.39	3.48	3.54	3.59	3.66	3.72	3.77	3.82	3.89	4.05	4.21	4.38	4.55	4.73	2.50%
JVILLE2			1.00	2.12	2.33	2.37	2.41	2.45	2.53	2.60	2.67	2.74	2.79	2.83	2.88	2.93	2.97	3.01	3.07	3.19	3.32	3.45	3.58	3.72	2.50%
Total Feeder Load				4.81	5.29	5.38	5.48	5.57	5.73	5.90	6.06	6.22	6.33	6.42	6.54	6.64	6.74	6.83	6.96	7.24	7.53	7.82	8.13	8.45	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
MARIBA	4.9	Regulator	1.00	3.97	4.36	4.44	4.52	4.60	4.73	4.87	5.00	5.14	5.23	5.30	5.39	5.48	5.56	5.64	5.74	5.97	6.21	6.45	6.71	6.97	2.50%
MARIBA1			1.00	0.63	0.69	0.71	0.72	0.73	0.75	0.77	0.79	0.82	0.83	0.84	0.86	0.87	0.88	0.89	0.91	0.95	0.99	1.02	1.06	1.11	2.50%
MARIBA2			1.00	2.07	2.27	2.31	2.35	2.39	2.46	2.53	2.60	2.67	2.72	2.76	2.81	2.85	2.89	2.93	2.99	3.11	3.23	3.36	3.49	3.63	2.50%
MARIBA3			1.00	1.05	1.14	1.16	1.19	1.20	1.24	1.28	1.31	1.35	1.37	1.39	1.41	1.44	1.46	1.48	1.51	1.57	1.63	1.69	1.76	1.83	2.50%
MARIBA4			1.00	0.24	0.26	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.31	0.32	0.32	0.33	0.33	0.34	0.35	0.37	0.38	0.40	0.41	2.50%
Total Feeder Load				3.99	4.36	4.44	4.52	4.60	4.73	4.87	5.00	5.14	5.23	5.30	5.39	5.48	5.56	5.64	5.74	5.97	6.21	6.45	6.71	6.97	-----
Substation Growth Factors					0.094	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				99.47%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
MILLER HUNT	11.1	Transformer	1.00	2.30	2.52	2.57	2.62	2.66	2.74	2.82	2.89	2.97	3.02	3.07	3.12	3.17	3.22	3.26	3.32	3.46	3.59	3.73	3.88	4.03	2.50%
MILLER HUNT1			1.00	1.26	1.38	1.41	1.43	1.46	1.50	1.54	1.59	1.63	1.66	1.68	1.71	1.74	1.76	1.79	1.82	1.89	1.97	2.05	2.13	2.21	2.50%
MILLER HUNT2			1.00	0.87	0.96	0.98	1.00	1.01	1.04	1.07	1.10	1.13	1.15	1.17	1.19	1.21	1.22	1.24	1.26	1.31	1.37	1.42	1.48	1.53	2.50%
MILLER HUNT3			1.00	0.16	0.18	0.18	0.19	0.19	0.20	0.20	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.29	2.50%
Total Feeder Load				2.30	2.52	2.57	2.62	2.66	2.74	2.82	2.89	2.97	3.02	3.07	3.12	3.17	3.22	3.26	3.32	3.46	3.59	3.73	3.88	4.03	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Summer) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2007 PEAK (MW)	PROJECTED LOADS (MW) LL1 2010	LL2 2011	LL3 2012	LL4 2013	LL5 2014	LL6 2015	LL7 2016	LL8 2017	LL9 2018	LL10 2019	LL11 2020	LL12 2021	LL13 2022	LL14 2023	LL15 2024	LL16 2025	LL17 2026	LL18 2027	LL19 2028	LL20 2029	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	2.11%
MT. STERLING	9.8	Regulator	1.00	4.78	5.25	5.35	5.45	5.54	5.70	5.86	6.02	6.18	6.29	6.38	6.49	6.60	6.70	6.79	6.92	7.19	7.48	7.77	8.08	8.39	2.50%
MTSTRLG1			1.00	1.14	1.25	1.27	1.30	1.32	1.36	1.40	1.43	1.47	1.50	1.52	1.55	1.57	1.60	1.62	1.65	1.71	1.78	1.85	1.92	2.00	2.50%
MTSTRLG2			1.00	2.21	2.43	2.48	2.52	2.57	2.64	2.72	2.79	2.87	2.92	2.96	3.01	3.06	3.10	3.15	3.21	3.33	3.47	3.60	3.74	3.89	2.50%
MTSTRLG3			1.00	1.43	1.57	1.60	1.62	1.65	1.70	1.75	1.80	1.84	1.88	1.90	1.94	1.97	2.00	2.02	2.06	2.15	2.23	2.32	2.41	2.50	2.50%
Total Feeder Load				4.78	5.25	5.35	5.45	5.54	5.70	5.86	6.02	6.18	6.29	6.38	6.49	6.60	6.70	6.79	6.92	7.19	7.48	7.77	8.08	8.39	-----
Substation Growth Factors					0.099	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				99.98%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
REID VILLAGE	4.9	Regulator	1.00	3.53	3.89	3.96	4.03	4.10	4.22	4.34	4.46	4.58	4.66	4.72	4.81	4.88	4.95	5.02	5.12	5.32	5.53	5.75	5.98	6.21	2.50%
RDVILLAGE1			1.00	1.72	2.91	2.96	3.01	3.06	3.15	3.24	3.33	3.42	3.48	3.53	3.60	3.65	3.71	3.76	3.83	3.98	4.14	4.30	4.47	4.65	2.50%
RDVILLAGE2			1.00	1.82	2.00	2.04	2.07	2.11	2.17	2.23	2.29	2.36	2.40	2.43	2.47	2.51	2.55	2.59	2.63	2.74	2.85	2.96	3.08	3.20	2.50%
Total Feeder Load				3.53	4.91	5.00	5.09	5.17	5.32	5.48	5.63	5.78	5.88	5.96	6.07	6.17	6.26	6.34	6.46	6.72	6.99	7.26	7.55	7.84	-----
Substation Growth Factors					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
SIDEVIEW	13.6	Transformer	1.00	5.22	5.74	5.84	5.95	6.05	6.23	6.40	6.58	6.76	6.88	6.97	7.10	7.21	7.32	7.42	7.56	7.86	8.17	8.49	8.83	9.17	2.50%
SIDEVIEW1			1.00	1.27	1.38	1.41	1.43	1.46	1.50	1.54	1.59	1.63	1.66	1.68	1.71	1.74	1.76	1.79	1.82	1.89	1.97	2.05	2.13	2.21	2.50%
SIDEVIEW2			1.00	1.35	1.47	1.50	1.52	1.55	1.59	1.64	1.68	1.73	1.76	1.78	1.82	1.84	1.87	1.90	1.93	2.01	2.09	2.17	2.26	2.35	2.50%
SIDEVIEW3			1.00	1.27	0.36	0.37	0.38	0.38	0.40	0.41	0.42	0.43	0.44	0.44	0.45	0.46	0.46	0.47	0.48	0.50	0.52	0.54	0.56	0.58	2.50%
SIDEVIEW4			1.00	1.38	1.50	1.53	1.56	1.58	1.63	1.67	1.72	1.77	1.80	1.82	1.86	1.89	1.91	1.94	1.98	2.06	2.14	2.22	2.31	2.40	2.50%
Total Feeder Load				5.26	4.72	4.80	4.89	4.97	5.12	5.26	5.41	5.55	5.65	5.73	5.83	5.93	6.01	6.10	6.21	6.46	6.72	6.98	7.25	7.54	-----
Substation Growth Factors					0.092	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				99.28%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
STANTON	19.5	Transformer	0.50	14.01	14.71	14.85	14.98	15.11	15.33	15.54	15.76	15.97	16.11	16.22	16.37	16.50	16.62	16.74	16.89	17.23	17.57	17.92	18.27	18.63	1.25%
STANTON1			1.00	2.95	3.10	3.13	3.16	3.18	3.23	3.27	3.32	3.36	3.39	3.42	3.45	3.48	3.50	3.53	3.56	3.63	3.70	3.77	3.85	3.92	1.25%
STANTON2			1.00	2.84	2.98	3.01	3.04	3.06	3.11	3.15	3.19	3.24	3.27	3.29	3.32	3.35	3.37	3.39	3.43	3.49	3.56	3.63	3.70	3.78	1.25%
STANTON3			1.00	2.92	3.07	3.09	3.12	3.15	3.19	3.24	3.28	3.33	3.36	3.38	3.41	3.44	3.46	3.49	3.52	3.59	3.66	3.73	3.81	3.88	1.25%
STANTON4			1.00	2.11	2.21	2.23	2.25	2.27	2.31	2.34	2.37	2.40	2.42	2.44	2.46	2.48	2.50	2.52	2.54	2.59	2.64	2.70	2.75	2.80	1.25%
STANTON5			1.00	3.19	3.35	3.38	3.41	3.44	3.49	3.54	3.59	3.64	3.67	3.70	3.73	3.76	3.79	3.81	3.85	3.92	4.00	4.08	4.16	4.24	1.25%
Total Feeder Load				14.01	14.71	14.85	14.98	15.11	15.33	15.54	15.76	15.97	16.11	16.22	16.37	16.50	16.62	16.74	16.89	17.23	17.57	17.92	18.27	18.63	-----
Substation Growth Factors					0.050	0.009	0.009	0.008	0.015	0.014	0.014	0.013	0.009	0.007	0.009	0.008	0.007	0.007	0.009	0.020	0.020	0.020	0.020	0.020	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
THREE FORKS	11.9	Transformer	0.75	3.45	3.70	3.75	3.80	3.85	3.94	4.02	4.10	4.19	4.24	4.29	4.34	4.40	4.44	4.49	4.55	4.69	4.83	4.97	5.12	5.27	1.87%
THRFRKS1			1.00	1.00	1.08	1.09	1.11	1.12	1.15	1.17	1.20	1.22	1.24	1.25	1.27	1.28	1.30	1.31	1.33	1.37	1.41	1.45	1.49	1.54	1.87%
THRFRKS2			1.00	2.14	2.30	2.34	2.37	2.40	2.45	2.50	2.55	2.61	2.64	2.67	2.70	2.74	2.77	2.79	2.83	2.92	3.01	3.09	3.19	3.28	1.87%
THRFRKS3			1.00	0.30	0.32	0.32	0.33	0.33	0.34	0.35	0.35	0.36	0.37	0.37	0.37	0.38	0.38	0.39	0.39	0.40	0.42	0.43	0.44	0.45	1.87%
Total Feeder Load				3.45	3.70	3.75	3.80	3.85	3.94	4.02	4.10	4.19	4.24	4.29	4.34	4.40	4.44	4.49	4.55	4.69	4.83	4.97	5.12	5.27	-----
Substation Growth Factors					0.075	0.014	0.014	0.012	0.022	0.021	0.021	0.020	0.013	0.010	0.014	0.012	0.011	0.010	0.014	0.030	0.030	0.030	0.029	0.029	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
TRAPP	4.4	Transformer	1.00	2.42	2.66	2.71	2.76	2.81	2.89	2.97	3.05	3.14	3.19	3.23	3.29	3.35	3.40	3.44	3.51	3.65	3.79	3.94	4.10	4.26	2.50%
TRAPP1			1.00	0.70	0.77	0.78	0.80	0.81	0.83	0.86	0.88	0.90	0.92	0.93	0.95	0.97	0.98	0.99	1.01	1.05	1.09	1.14	1.18	1.23	2.50%
TRAPP2			1.00	1.18	1.29	1.32	1.34	1.36	1.40	1.44	1.48	1.52	1.55	1.57	1.60	1.63	1.65	1.67	1.71	1.77	1.84	1.92	1.99	2.07	2.50%
TRAPP3			1.00	0.55	0.60	0.61	0.62	0.63	0.65	0.67	0.69	0.71	0.72	0.73	0.74	0.75	0.77	0.78	0.79	0.82	0.85	0.89	0.92	0.96	2.50%
Total Feeder Load				2.42	2.66	2.71	2.76	2.81	2.89	2.97	3.05	3.14	3.19	3.23	3.29	3.35	3.40	3.44	3.51	3.65	3.79	3.94	4.10	4.26	-----
Substation Growth Factors					0.099	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				99.96%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Summer) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2007 PEAK (MW)	PROJECTED LOADS (MW) LL1 2010	LL2 2011	LL3 2012	LL4 2013	LL5 2014	LL6 2015	LL7 2016	LL8 2017	LL9 2018	LL10 2019	LL11 2020	LL12 2021	LL13 2022	LL14 2023	LL15 2024	LL16 2025	LL17 2026	LL18 2027	LL19 2028	LL20 2029	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	2.11%
TREEHAVEN	4.9	Regulator	0.50	3.46	3.63	3.66	3.70	3.73	3.78	3.83	3.89	3.94	3.98	4.00	4.04	4.07	4.10	4.13	4.17	4.25	4.34	4.42	4.51	4.60	1.25%
TREEHAVEN1			1.00	0.87	0.91	0.92	0.93	0.94	0.95	0.97	0.98	0.99	1.00	1.01	1.02	1.02	1.03	1.04	1.05	1.07	1.09	1.11	1.13	1.16	1.25%
TREEHAVEN2			1.00	1.92	2.01	2.03	2.05	2.06	2.09	2.12	2.15	2.18	2.20	2.22	2.24	2.25	2.27	2.29	2.31	2.35	2.40	2.45	2.50	2.55	1.25%
TREEHAVEN3			1.00	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	1.25%
TREEHAVEN4			1.00	0.59	0.62	0.63	0.64	0.64	0.65	0.66	0.67	0.68	0.68	0.69	0.69	0.70	0.70	0.71	0.72	0.73	0.74	0.76	0.77	0.79	1.25%
Total Feeder Load				3.46	3.63	3.66	3.70	3.73	3.78	3.83	3.89	3.94	3.98	4.00	4.04	4.07	4.10	4.13	4.17	4.25	4.34	4.42	4.51	4.60	-----
Substation Growth Factors					0.050	0.009	0.009	0.008	0.015	0.014	0.014	0.013	0.009	0.007	0.009	0.008	0.007	0.007	0.009	0.020	0.020	0.020	0.020	0.020	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
UNION CITY	11.9	Transformer	1.50	5.19	5.97	6.13	6.30	6.46	6.74	7.03	7.32	7.61	7.82	7.98	8.19	8.39	8.58	8.75	9.00	9.54	10.10	10.70	11.33	12.00	3.74%
UNIONCITY1			1.00	1.68	1.93	1.98	2.04	2.09	2.18	2.27	2.37	2.46	2.53	2.58	2.65	2.71	2.77	2.83	2.91	3.09	3.27	3.46	3.67	3.88	3.74%
UNIONCITY2			1.00	1.39	1.60	1.64	1.68	1.73	1.80	1.88	1.96	2.04	2.09	2.13	2.19	2.24	2.29	2.34	2.41	2.55	2.70	2.86	3.03	3.21	3.74%
UNIONCITY3			1.00	0.82	0.95	0.97	1.00	1.02	1.07	1.11	1.16	1.21	1.24	1.26	1.30	1.33	1.36	1.39	1.43	1.51	1.60	1.70	1.80	1.90	3.74%
UNIONCITY4			1.00	1.30	1.50	1.54	1.58	1.62	1.69	1.76	1.83	1.91	1.96	2.00	2.05	2.10	2.15	2.19	2.26	2.39	2.53	2.68	2.84	3.01	3.74%
Total Feeder Load				5.19	5.97	6.13	6.30	6.46	6.74	7.03	7.32	7.61	7.82	7.98	8.19	8.39	8.58	8.75	9.00	9.54	10.10	10.70	11.33	12.00	-----
Substation Growth Factors					0.150	0.028	0.027	0.025	0.044	0.043	0.042	0.040	0.027	0.020	0.027	0.024	0.022	0.021	0.028	0.060	0.059	0.059	0.059	0.059	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
VAN METER	6.3	Transformer	1.00	2.44	2.68	2.73	2.78	2.82	2.91	2.99	3.07	3.15	3.21	3.25	3.31	3.37	3.42	3.46	3.53	3.67	3.81	3.96	4.12	4.28	2.50%
VANMTR1			1.00	0.18	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.31	0.32	2.50%
VANMTR2			1.00	0.24	0.27	0.28	0.28	0.29	0.29	0.30	0.31	0.32	0.32	0.33	0.33	0.34	0.35	0.35	0.36	0.37	0.39	0.40	0.42	0.43	2.50%
VANMTR3			1.00	1.98	2.21	2.25	2.29	2.33	2.39	2.46	2.53	2.60	2.64	2.68	2.73	2.77	2.81	2.85	2.91	3.02	3.14	3.27	3.39	3.53	2.50%
Total Feeder Load				2.41	2.68	2.73	2.78	2.82	2.91	2.99	3.07	3.15	3.21	3.25	3.31	3.37	3.42	3.46	3.53	3.67	3.81	3.96	4.12	4.28	-----
Substation Growth Factors					0.114	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
Substation Coincident Factor				101.29%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
COINCIDENT SYSTEM PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	-----
TOT. NON-COINCIDENT SUB. PEAK				97.64	105.60	107.20	108.80	110.30	112.98	115.65	118.33	121.00	122.80	124.20	126.10	127.80	129.40	130.90	133.00	137.50	142.15	146.95	151.92	157.05	-----
SYSTEM GROWTH FACTORS					0.100	0.018	0.018	0.017	0.029	0.028	0.028	0.027	0.018	0.014	0.018	0.016	0.015	0.014	0.019	0.040	0.040	0.039	0.039	0.039	-----
SYSTEM COINCIDENT FACTOR				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Notes: (1) Historical system coincident and substation non-coincident peak loads provided by Clark Energy
(2) Projected coincident system peak from adjusted 2008 EKPC Load Forecast.

Clark Energy Cooperative, Inc.
(Winter) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2009 PEAK (MW)	PROJECTED LOADS (MW) LL1 2011	LL2 2012	LL3 2013	LL4 2014	LL5 2015	LL6 2016	LL7 2017	LL8 2018	LL9 2019	LL10 2020	LL11 2021	LL12 2022	LL13 2023	LL14 2024	LL15 2025	LL16 2026	LL17 2027	LL18 2028	LL19 2029	LL20 2030	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	2.54%
BLEVINS VALLEY	7.5	Transformer	0.75	4.30	4.37	4.45	4.53	4.59	4.75	4.91	5.07	5.22	5.31	5.38	5.47	5.55	5.63	5.70	5.80	5.94	6.08	6.22	6.37	6.52	2.13%
BLEVAL1			1.00	1.68	1.71	1.74	1.77	1.79	1.86	1.92	1.98	2.04	2.07	2.10	2.14	2.17	2.20	2.23	2.26	2.32	2.37	2.43	2.49	2.55	2.13%
BLEVAL2			1.00	2.08	2.12	2.15	2.19	2.22	2.30	2.38	2.45	2.53	2.57	2.61	2.65	2.69	2.73	2.76	2.81	2.87	2.94	3.01	3.08	3.16	2.13%
BLEVAL3			1.00	0.54	0.55	0.56	0.57	0.58	0.60	0.62	0.64	0.66	0.67	0.68	0.69	0.70	0.71	0.72	0.73	0.74	0.76	0.78	0.80	0.82	2.13%
Total Feeder Load				4.30	4.37	4.45	4.53	4.59	4.75	4.91	5.07	5.22	5.31	5.38	5.47	5.55	5.63	5.70	5.80	5.94	6.08	6.22	6.37	6.52	-----
Substation Growth Factors					0.016	0.017	0.019	0.014	0.035	0.033	0.032	0.031	0.016	0.014	0.017	0.015	0.014	0.012	0.017	0.024	0.024	0.024	0.024	0.024	-----
Substation Coincident Factor				99.98%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
BOWEN	7.9	Transformer	0.10	4.07	4.08	4.08	4.09	4.10	4.12	4.14	4.16	4.17	4.18	4.19	4.20	4.21	4.22	4.22	4.23	4.25	4.26	4.27	4.29	4.30	0.28%
BOWEN1			1.00	1.82	1.82	1.82	1.83	1.83	1.84	1.85	1.86	1.86	1.87	1.87	1.88	1.88	1.88	1.89	1.89	1.90	1.90	1.91	1.92	1.92	0.28%
BOWEN2			1.00	1.26	1.26	1.26	1.27	1.27	1.27	1.28	1.28	1.29	1.29	1.30	1.30	1.30	1.30	1.31	1.31	1.31	1.32	1.32	1.32	1.33	0.28%
BOWEN3			1.00	0.99	1.00	1.00	1.00	1.00	1.01	1.01	1.02	1.02	1.02	1.02	1.03	1.03	1.03	1.03	1.03	1.04	1.04	1.04	1.05	1.05	0.28%
Total Feeder Load				4.07	4.08	4.08	4.09	4.10	4.12	4.14	4.16	4.17	4.18	4.19	4.20	4.21	4.22	4.22	4.23	4.25	4.26	4.27	4.29	4.30	-----
Substation Growth Factors					0.002	0.002	0.002	0.002	0.005	0.004	0.004	0.004	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003	-----
Substation Coincident Factor				99.98%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
CAVE RUN	3.0	Transformer	0.50	1.73	1.75	1.77	1.79	1.81	1.85	1.89	1.93	1.97	1.99	2.01	2.03	2.05	2.07	2.09	2.11	2.14	2.18	2.21	2.25	2.28	1.42%
CAVERUN1			1.00	0.81	0.82	0.83	0.84	0.85	0.87	0.89	0.91	0.93	0.94	0.95	0.96	0.97	0.97	0.98	0.99	1.01	1.03	1.04	1.06	1.07	1.42%
CAVERUN2			1.00	0.92	0.92	0.93	0.95	0.96	0.98	1.00	1.02	1.04	1.05	1.06	1.07	1.08	1.10	1.10	1.12	1.13	1.15	1.17	1.19	1.21	1.42%
Total Feeder Load				1.73	1.75	1.77	1.79	1.81	1.85	1.89	1.93	1.97	1.99	2.01	2.03	2.05	2.07	2.09	2.11	2.14	2.18	2.21	2.25	2.28	-----
Substation Growth Factors					0.010	0.011	0.012	0.010	0.023	0.022	0.021	0.020	0.011	0.009	0.011	0.010	0.010	0.008	0.011	0.016	0.016	0.016	0.016	0.016	-----
Substation Coincident Factor				99.94%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
CLAY CITY	17.1	Fuse	0.80	11.03	11.22	11.42	11.65	11.83	12.27	12.71	13.14	13.57	13.80	14.01	14.26	14.48	14.70	14.90	15.16	15.55	15.94	16.35	16.76	17.19	2.27%
CLAYCTY1			1.00	3.80	3.87	3.94	4.02	4.08	4.23	4.38	4.53	4.68	4.76	4.83	4.92	4.99	5.07	5.14	5.23	5.36	5.50	5.64	5.78	5.93	2.27%
CLAYCTY2			1.00	2.14	2.18	2.22	2.26	2.30	2.38	2.47	2.55	2.64	2.68	2.72	2.77	2.81	2.86	2.89	2.95	3.02	3.10	3.18	3.26	3.34	2.27%
CLAYCTY3			1.00	2.40	2.44	2.48	2.53	2.57	2.67	2.76	2.86	2.95	3.00	3.04	3.10	3.15	3.20	3.24	3.29	3.38	3.47	3.55	3.64	3.74	2.27%
CLAYCTY4			1.00	2.69	2.73	2.78	2.84	2.88	2.99	3.09	3.20	3.30	3.36	3.41	3.47	3.53	3.58	3.63	3.69	3.78	3.88	3.98	4.08	4.18	2.27%
Total Feeder Load				11.03	11.22	11.42	11.65	11.83	12.27	12.71	13.14	13.57	13.80	14.01	14.26	14.48	14.70	14.90	15.16	15.55	15.94	16.35	16.76	17.19	-----
Substation Growth Factors					0.017	0.018	0.020	0.015	0.037	0.036	0.034	0.033	0.017	0.015	0.018	0.016	0.015	0.013	0.018	0.026	0.026	0.025	0.025	0.025	-----
Substation Coincident Factor				100.01%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
FRENCHBURG	14.4	Tap Changer	0.50	9.27	9.37	9.48	9.59	9.69	9.91	10.13	10.35	10.56	10.67	10.77	10.89	11.00	11.10	11.19	11.32	11.50	11.68	11.87	12.05	12.25	1.42%
FRNBURG1			1.00	1.95	1.97	2.00	2.02	2.04	2.09	2.13	2.18	2.22	2.25	2.27	2.29	2.32	2.34	2.36	2.38	2.42	2.46	2.50	2.54	2.58	1.42%
FRNBURG2			1.00	1.70	1.72	1.74	1.76	1.78	1.82	1.86	1.90	1.94	1.96	1.97	2.00	2.02	2.04	2.05	2.07	2.11	2.14	2.18	2.21	2.24	1.42%
FRNBURG3			1.00	2.79	2.82	2.85	2.89	2.92	2.99	3.05	3.12	3.18	3.21	3.24	3.28	3.31	3.34	3.37	3.41	3.46	3.52	3.57	3.63	3.69	1.42%
FRNBURG4			1.00	2.83	2.86	2.89	2.92	2.95	3.02	3.09	3.15	3.22	3.25	3.28	3.32	3.35	3.39	3.41	3.45	3.51	3.56	3.62	3.68	3.73	1.42%
Total Feeder Load				9.27	9.37	9.48	9.59	9.69	9.91	10.13	10.35	10.56	10.67	10.77	10.89	11.00	11.10	11.19	11.32	11.50	11.68	11.87	12.05	12.25	-----
Substation Growth Factors					0.011	0.011	0.012	0.010	0.023	0.022	0.021	0.020	0.011	0.009	0.011	0.010	0.010	0.008	0.011	0.016	0.016	0.016	0.016	0.016	-----
Substation Coincident Factor				100.02%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
Grayson Meter PT	0.1		0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00%
Grayson			1.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00%
Total Feeder Load				0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	-----
Substation Growth Factors					0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HARDWICKS CREEK	14.4	Tap Changer	1.00	3.47	3.54	3.62	3.71	3.78	3.96	4.13	4.31	4.48	4.58	4.67	4.77	4.86	4.96	5.04	5.15	5.31	5.48	5.66	5.84	6.02	2.84%
HARDWICKS1			1.00	2.42	2.47	2.53	2.59	2.64	2.76	2.89	3.01	3.13	3.20	3.26	3.33	3.40	3.46	3.52	3.60	3.71	3.83	3.95	4.08	4.21	2.84%
HARDWICKS2			1.00	0.44	0.44	0.45	0.47	0.47	0.50	0.52	0.54	0.56	0.57	0.59	0.60	0.61	0.62	0.63	0.65	0.67	0.69	0.71	0.73	0.76	2.84%
HARDWICKS3			1.00	0.61	0.62	0.63	0.65	0.66	0.69	0.72	0.76	0.79	0.80	0.82	0.84	0.85	0.87	0.88	0.90	0.93	0.96	0.99	1.02	1.06	2.84%
Total Feeder Load				3.47	3.54	3.62	3.71	3.78	3.96	4.13	4.31	4.48	4.58	4.67	4.77	4.86	4.96	5.04	5.15	5.31	5.48	5.66	5.84	6.02	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Winter) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2009 PEAK (MW)	PROJECTED LOADS (MW)																				COMP. ANNUAL GROWTH
					LL1 2011	LL2 2012	LL3 2013	LL4 2014	LL5 2015	LL6 2016	LL7 2017	LL8 2018	LL9 2019	LL10 2020	LL11 2021	LL12 2022	LL13 2023	LL14 2024	LL15 2025	LL16 2026	LL17 2027	LL18 2028	LL19 2029	LL20 2030	
PROJECTED SYSTEM NON-COINCIDENT PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	2.54%
HIGH ROCK	1.4	Transformer	0.50	0.70	0.71	0.72	0.73	0.73	0.75	0.77	0.78	0.80	0.81	0.82	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.93	1.42%
HIGHROCK1			1.00	0.70	0.71	0.72	0.73	0.73	0.75	0.77	0.78	0.80	0.81	0.82	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.93	1.42%
Total Feeder Load				0.70	0.71	0.72	0.73	0.73	0.75	0.77	0.78	0.80	0.81	0.82	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.90	0.91	0.93	-----
Substation Growth Factors					0.011	0.011	0.012	0.010	0.023	0.022	0.021	0.020	0.011	0.009	0.011	0.010	0.010	0.008	0.011	0.016	0.016	0.016	0.016	0.016	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HINKSTON	17.1	Fuse	1.00	4.35	4.44	4.54	4.65	4.74	4.96	5.18	5.40	5.62	5.74	5.85	5.98	6.10	6.22	6.32	6.46	6.66	6.88	7.10	7.32	7.55	2.84%
HINKSTON1			1.00	0.41	0.42	0.43	0.44	0.45	0.47	0.49	0.51	0.53	0.54	0.55	0.56	0.57	0.58	0.59	0.61	0.63	0.65	0.67	0.69	0.71	2.84%
HINKSTON2			1.00	1.71	1.74	1.78	1.82	1.86	1.95	2.03	2.12	2.21	2.25	2.30	2.35	2.39	2.44	2.48	2.53	2.61	2.70	2.78	2.87	2.96	2.84%
HINKSTON3			1.00	1.74	1.78	1.82	1.86	1.90	1.99	2.07	2.16	2.25	2.30	2.34	2.39	2.44	2.49	2.53	2.58	2.67	2.75	2.84	2.93	3.02	2.84%
HINKSTON4			1.00	0.49	0.50	0.52	0.53	0.54	0.56	0.59	0.61	0.64	0.65	0.67	0.68	0.69	0.71	0.72	0.73	0.76	0.78	0.81	0.83	0.86	2.84%
Total Feeder Load				4.35	4.44	4.54	4.65	4.74	4.96	5.18	5.40	5.62	5.74	5.85	5.98	6.10	6.22	6.32	6.46	6.66	6.88	7.10	7.32	7.55	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HOPE	8.9	Fuse	1.00	6.11	6.24	6.38	6.53	6.66	6.97	7.28	7.59	7.90	8.07	8.22	8.41	8.57	8.73	8.88	9.07	9.36	9.66	9.97	10.28	10.61	2.84%
HOPE1			1.00	0.44	0.45	0.46	0.47	0.48	0.50	0.52	0.54	0.57	0.58	0.59	0.60	0.61	0.63	0.64	0.65	0.67	0.69	0.71	0.74	0.76	2.84%
HOPE2			1.00	1.53	1.56	1.60	1.64	1.67	1.75	1.82	1.90	1.98	2.02	2.06	2.11	2.15	2.19	2.22	2.27	2.35	2.42	2.50	2.58	2.66	2.84%
HOPE3			1.00	4.14	4.23	4.32	4.43	4.51	4.72	4.93	5.14	5.35	5.47	5.57	5.70	5.81	5.92	6.01	6.15	6.34	6.55	6.75	6.97	7.19	2.84%
Total Feeder Load				6.11	6.24	6.38	6.53	6.66	6.97	7.28	7.59	7.90	8.07	8.22	8.41	8.57	8.73	8.88	9.07	9.36	9.66	9.97	10.28	10.61	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				99.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
HUNT	13.7	Fuse	1.00	10.74	10.97	11.22	11.50	11.72	12.26	12.81	13.35	13.90	14.19	14.46	14.79	15.08	15.36	15.61	15.96	16.47	16.99	17.53	18.09	18.66	2.84%
HUNT1			1.00	2.02	2.07	2.11	2.17	2.21	2.31	2.41	2.52	2.62	2.67	2.72	2.79	2.84	2.89	2.94	3.01	3.10	3.20	3.30	3.41	3.52	2.84%
HUNT2			1.00	0.61	0.62	0.64	0.65	0.67	0.70	0.73	0.76	0.79	0.81	0.82	0.84	0.86	0.87	0.89	0.91	0.94	0.97	1.00	1.03	1.06	2.84%
HUNT3			1.00	3.64	3.71	3.80	3.89	3.97	4.15	4.34	4.52	4.71	4.81	4.90	5.01	5.11	5.20	5.29	5.40	5.58	5.76	5.94	6.13	6.32	2.84%
HUNT4			1.00	4.47	4.56	4.67	4.78	4.88	5.10	5.33	5.56	5.78	5.91	6.02	6.15	6.27	6.39	6.50	6.64	6.85	7.07	7.30	7.53	7.77	2.84%
Total Feeder Load				10.75	10.97	11.22	11.50	11.72	12.26	12.81	13.35	13.90	14.19	14.46	14.79	15.08	15.36	15.61	15.96	16.47	16.99	17.53	18.09	18.66	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				99.97%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
JEFFERSONVILLE	13.7	Fuse	1.00	6.98	7.13	7.29	7.47	7.62	7.97	8.32	8.68	9.03	9.22	9.40	9.61	9.80	9.98	10.15	10.37	10.70	11.04	11.40	11.76	12.13	2.84%
JVILLE1			1.00	4.36	4.45	4.55	4.66	4.75	4.98	5.20	5.42	5.64	5.76	5.87	6.00	6.12	6.23	6.34	6.47	6.68	6.90	7.11	7.34	7.57	2.84%
JVILLE2			1.00	2.62	2.68	2.74	2.81	2.86	2.99	3.13	3.26	3.39	3.47	3.53	3.61	3.68	3.75	3.81	3.90	4.02	4.15	4.28	4.42	4.56	2.84%
Total Feeder Load				6.99	7.13	7.29	7.47	7.62	7.97	8.32	8.68	9.03	9.22	9.40	9.61	9.80	9.98	10.15	10.37	10.70	11.04	11.40	11.76	12.13	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				99.94%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
MARIBA	7.5	Regulator	1.00	6.10	6.23	6.37	6.53	6.65	6.96	7.27	7.58	7.89	8.06	8.21	8.40	8.56	8.72	8.87	9.06	9.35	9.65	9.96	10.27	10.60	2.84%
MARIBA1			1.00	0.90	0.91	0.94	0.96	0.98	1.02	1.07	1.11	1.16	1.18	1.21	1.23	1.26	1.28	1.30	1.33	1.37	1.42	1.46	1.51	1.56	2.84%
MARIBA2			1.00	3.15	3.21	3.28	3.37	3.43	3.59	3.75	3.91	4.07	4.15	4.23	4.33	4.41	4.50	4.57	4.67	4.82	4.97	5.13	5.30	5.46	-0.69%
MARIBA3			1.00	1.60	1.64	1.67	1.72	1.75	1.83	1.91	1.99	2.07	2.12	2.16	2.21	2.25	2.29	2.33	2.38	2.46	2.54	2.62	2.70	2.78	2.84%
MARIBA4			1.00	0.46	0.47	0.48	0.49	0.50	0.52	0.55	0.57	0.59	0.60	0.62	0.63	0.64	0.65	0.67	0.68	0.70	0.72	0.75	0.77	0.80	2.84%
Total Feeder Load				6.11	6.23	6.37	6.53	6.65	6.96	7.27	7.58	7.89	8.06	8.21	8.40	8.56	8.72	8.87	9.06	9.35	9.65	9.96	10.27	10.60	-----
Substation Growth Factors					0.020	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				99.92%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
MILLER HUNT	15.7	Transformer	1.00	3.01	3.07	3.14	3.22	3.28	3.43	3.59	3.74	3.89	3.97	4.05	4.14	4.22	4.30	4.37	4.47	4.61	4.76	4.91	5.06	5.22	2.84%
MILLER HUNT1			1.00	1.56	1.59	1.63	1.67	1.70	1.78	1.86	1.94	2.02	2.06	2.10	2.15	2.19	2.23	2.27	2.32	2.39	2.47	2.54	2.63	2.71	2.84%
MILLER HUNT2			1.00	1.22	1.25	1.28	1.31	1.33	1.40	1.46	1.52	1.58	1.62	1.65	1.68	1.72	1.75	1.78	1.82	1.88	1.93	2.00	2.06	2.12	2.84%
MILLER HUNT3			1.00	0.23	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.33	0.34	0.36	0.37	0.38	0.39	2.84%
Total Feeder Load				3.01	3.07	3.14	3.22	3.28	3.43	3.59	3.74	3.89	3.97	4.05	4.14	4.22	4.30	4.37	4.47	4.61	4.76	4.91	5.06	5.22	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Winter) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2009 PEAK (MW)	PROJECTED LOADS (MW) LL1 2011	LL2 2012	LL3 2013	LL4 2014	LL5 2015	LL6 2016	LL7 2017	LL8 2018	LL9 2019	LL10 2020	LL11 2021	LL12 2022	LL13 2023	LL14 2024	LL15 2025	LL16 2026	LL17 2027	LL18 2028	LL19 2029	LL20 2030	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	2.54%
MT. STERLING	13.7	Fuse	1.00	6.93	7.08	7.24	7.42	7.56	7.91	8.26	8.61	8.96	9.16	9.33	9.54	9.72	9.91	10.07	10.29	10.62	10.96	11.31	11.67	12.04	2.84%
MTSTRLG1			1.00	1.27	1.30	1.33	1.36	1.39	1.45	1.52	1.58	1.64	1.68	1.71	1.75	1.78	1.82	1.85	1.89	1.95	2.01	2.07	2.14	2.21	2.84%
MTSTRLG2			1.00	3.41	3.48	3.56	3.65	3.72	3.89	4.06	4.24	4.41	4.50	4.59	4.69	4.78	4.87	4.95	5.06	5.22	5.39	5.56	5.74	5.92	2.84%
MTSTRLG3			1.00	2.25	2.30	2.35	2.41	2.45	2.57	2.68	2.80	2.91	2.97	3.03	3.10	3.16	3.22	3.27	3.34	3.45	3.56	3.67	3.79	3.91	2.84%
Total Feeder Load				6.93	7.08	7.24	7.42	7.56	7.91	8.26	8.61	8.96	9.16	9.33	9.54	9.72	9.91	10.07	10.29	10.62	10.96	11.31	11.67	12.04	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.01%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
REID VILLAGE	6.8	Fuse	1.00	4.21	4.30	4.39	4.50	4.59	4.80	5.02	5.23	5.44	5.56	5.67	5.79	5.91	6.02	6.12	6.25	6.45	6.66	6.87	7.09	7.31	2.84%
RDVILLAGE1			1.00	2.52	2.57	2.63	2.70	2.75	2.88	3.00	3.13	3.26	3.33	3.39	3.47	3.54	3.60	3.66	3.74	3.86	3.99	4.11	4.24	4.38	2.84%
RDVILLAGE2			1.00	1.69	1.72	1.76	1.81	1.84	1.93	2.01	2.10	2.18	2.23	2.27	2.32	2.37	2.41	2.45	2.51	2.59	2.67	2.76	2.84	2.93	2.84%
Total Feeder Load				4.21	4.30	4.39	4.50	4.59	4.80	5.02	5.23	5.44	5.56	5.67	5.79	5.91	6.02	6.12	6.25	6.45	6.66	6.87	7.09	7.31	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
SIDEVIEW	14.4	Tap Changer	1.00	9.54	9.74	9.96	10.21	10.41	10.89	11.37	11.86	12.34	12.60	12.84	13.13	13.39	13.64	13.86	14.17	14.62	15.09	15.57	16.06	16.57	2.84%
SIDEVIEW1			1.00	2.38	2.44	2.50	2.56	2.61	2.73	2.85	2.97	3.09	3.16	3.22	3.29	3.35	3.42	3.47	3.55	3.66	3.78	3.90	4.02	4.15	2.84%
SIDEVIEW2			1.00	2.15	2.20	2.25	2.30	2.35	2.46	2.57	2.67	2.78	2.84	2.90	2.96	3.02	3.08	3.13	3.20	3.30	3.40	3.51	3.62	3.74	2.84%
SIDEVIEW3			1.00	2.54	2.60	2.66	2.73	2.78	2.91	3.04	3.17	3.30	3.37	3.43	3.51	3.58	3.64	3.70	3.78	3.91	4.03	4.16	4.29	4.43	2.84%
SIDEVIEW4			1.00	2.44	2.50	2.56	2.62	2.67	2.80	2.92	3.04	3.17	3.24	3.30	3.37	3.44	3.50	3.56	3.64	3.76	3.87	4.00	4.12	4.26	2.84%
Total Feeder Load				9.52	9.74	9.96	10.21	10.41	10.89	11.37	11.86	12.34	12.60	12.84	13.13	13.39	13.64	13.86	14.17	14.62	15.09	15.57	16.06	16.57	-----
Substation Growth Factors					0.023	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.22%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
STANTON	23.6	Tap Changer	0.50	12.50	12.63	12.78	12.94	13.06	13.36	13.66	13.95	14.24	14.39	14.52	14.69	14.83	14.97	15.09	15.26	15.50	15.75	16.00	16.26	16.51	1.42%
STANTON1			1.00	2.29	2.32	2.34	2.37	2.39	2.45	2.51	2.56	2.61	2.64	2.66	2.69	2.72	2.74	2.76	2.80	2.84	2.89	2.93	2.98	3.03	1.42%
STANTON2			1.00	2.53	2.56	2.59	2.62	2.65	2.71	2.77	2.83	2.89	2.92	2.94	2.98	3.01	3.03	3.06	3.09	3.15	3.19	3.25	3.30	3.35	1.42%
STANTON3			1.00	2.69	2.72	2.75	2.79	2.82	2.89	2.95	3.01	3.07	3.10	3.13	3.17	3.20	3.23	3.25	3.29	3.35	3.40	3.45	3.51	3.56	1.42%
STANTON4			1.00	1.65	1.67	1.69	1.71	1.73	1.77	1.81	1.85	1.89	1.91	1.92	1.95	1.96	1.98	2.00	2.02	2.05	2.09	2.12	2.15	2.19	1.42%
STANTON5			1.00	3.34	3.38	3.42	3.46	3.49	3.58	3.66	3.74	3.81	3.85	3.88	3.93	3.97	4.00	4.04	4.08	4.15	4.22	4.28	4.35	4.42	1.42%
Total Feeder Load				12.50	12.65	12.80	12.96	13.08	13.41	13.70	13.99	14.27	14.41	14.54	14.71	14.85	14.99	15.11	15.28	15.54	15.78	16.04	16.29	16.55	-----
Substation Growth Factors					0.012	0.011	0.013	0.009	0.025	0.022	0.021	0.020	0.009	0.010	0.011	0.009	0.010	0.008	0.011	0.017	0.016	0.016	0.016	0.016	-----
Substation Coincident Factor				100.02%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
THREE FORKS	16.8	Transformer	0.75	6.37	6.47	6.58	6.70	6.80	7.03	7.27	7.50	7.73	7.85	7.96	8.10	8.22	8.33	8.44	8.57	8.78	8.99	9.20	9.42	9.65	2.13%
THRFRKS1			1.00	1.78	1.80	1.83	1.87	1.89	1.96	2.03	2.09	2.15	2.19	2.22	2.26	2.29	2.32	2.35	2.39	2.45	2.51	2.57	2.63	2.69	2.13%
THRFRKS2			1.00	4.01	4.07	4.14	4.22	4.28	4.43	4.57	4.72	4.87	4.94	5.01	5.10	5.17	5.25	5.31	5.40	5.53	5.66	5.79	5.93	6.07	2.13%
THRFRKS3			1.00	0.58	0.59	0.60	0.61	0.62	0.64	0.67	0.69	0.71	0.72	0.73	0.74	0.75	0.76	0.77	0.79	0.81	0.82	0.84	0.86	0.88	2.13%
Total Feeder Load				6.37	6.47	6.58	6.70	6.80	7.03	7.27	7.50	7.73	7.85	7.96	8.10	8.22	8.33	8.44	8.57	8.78	8.99	9.20	9.42	9.65	-----
Substation Growth Factors					0.015	0.017	0.019	0.014	0.035	0.033	0.032	0.031	0.016	0.014	0.017	0.015	0.014	0.012	0.017	0.024	0.024	0.024	0.024	0.024	-----
Substation Coincident Factor				99.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
TRAPP	6.8	Fuse	1.00	3.59	3.66	3.75	3.84	3.91	4.09	4.28	4.46	4.64	4.74	4.83	4.94	5.03	5.13	5.21	5.33	5.50	5.67	5.85	6.04	6.23	2.84%
TRAPP1			1.00	1.11	1.13	1.15	1.18	1.21	1.26	1.32	1.37	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.69	1.75	1.80	1.86	1.92	2.84%
TRAPP2			1.00	1.81	1.85	1.89	1.94	1.98	2.07	2.16	2.25	2.35	2.40	2.44	2.50	2.55	2.59	2.64	2.69	2.78	2.87	2.96	3.05	3.15	2.84%
TRAPP3			1.00	0.67	0.68	0.70	0.71	0.73	0.76	0.80	0.83	0.86	0.88	0.90	0.92	0.94	0.95	0.97	0.99	1.02	1.06	1.09	1.12	1.16	2.84%
Total Feeder Load				3.59	3.66	3.75	3.84	3.91	4.09	4.28	4.46	4.64	4.74	4.83	4.94	5.03	5.13	5.21	5.33	5.50	5.67	5.85	6.04	6.23	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Clark Energy Cooperative, Inc.
(Winter) Substation and Feeder Load Forecast

SUBSTATION / FEEDER NAME	TOTAL CAPACITY (MVA)	LIMITING ELEMENT	RELATIVE GROWTH FACTOR	2009 PEAK (MW)	PROJECTED LOADS (MW) LL1 2011	LL2 2012	LL3 2013	LL4 2014	LL5 2015	LL6 2016	LL7 2017	LL8 2018	LL9 2019	LL10 2020	LL11 2021	LL12 2022	LL13 2023	LL14 2024	LL15 2025	LL16 2026	LL17 2027	LL18 2028	LL19 2029	LL20 2030	COMP. ANNUAL GROWTH
PROJECTED SYSTEM NON-COINCIDENT PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	2.54%
TREEHAVEN	7.5	Regulator	0.50	3.74	3.78	3.82	3.87	3.91	4.00	4.09	4.17	4.26	4.30	4.34	4.39	4.44	4.48	4.51	4.56	4.64	4.71	4.79	4.86	4.94	1.42%
TREEHAVEN1			1.00	0.86	0.87	0.88	0.89	0.90	0.92	0.94	0.96	0.98	0.99	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.08	1.10	1.12	1.13	1.42%
TREEHAVEN2			1.00	1.74	1.75	1.77	1.80	1.81	1.85	1.90	1.94	1.98	2.00	2.02	2.04	2.06	2.08	2.09	2.12	2.15	2.19	2.22	2.26	2.29	1.42%
TREEHAVEN3			1.00	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	1.42%
TREEHAVEN4			1.00	0.98	0.99	1.00	1.01	1.02	1.05	1.07	1.09	1.11	1.13	1.14	1.15	1.16	1.17	1.18	1.20	1.21	1.23	1.25	1.27	1.29	1.42%
Total Feeder Load				3.74	3.78	3.82	3.87	3.91	4.00	4.09	4.17	4.26	4.30	4.34	4.39	4.44	4.48	4.51	4.56	4.64	4.71	4.79	4.86	4.94	-----
Substation Growth Factors					0.011	0.011	0.012	0.010	0.023	0.022	0.021	0.020	0.011	0.009	0.011	0.010	0.010	0.008	0.011	0.016	0.016	0.016	0.016	0.016	-----
Substation Coincident Factor				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
UNION CITY	16.8	Transformer	1.50	10.96	11.31	11.69	12.13	12.48	13.35	14.24	15.15	16.07	16.59	17.06	17.64	18.15	18.67	19.13	19.76	20.71	21.70	22.73	23.82	24.94	4.25%
UNIONCITY1			1.00	3.50	3.60	3.73	3.87	3.98	4.25	4.54	4.83	5.12	5.29	5.44	5.62	5.79	5.95	6.10	6.30	6.60	6.92	7.25	7.59	7.95	4.25%
UNIONCITY2			1.00	2.63	2.72	2.81	2.91	3.00	3.21	3.42	3.64	3.86	3.98	4.10	4.24	4.36	4.48	4.59	4.75	4.97	5.21	5.46	5.72	5.99	4.25%
UNIONCITY3			1.00	1.74	1.79	1.85	1.92	1.97	2.11	2.25	2.40	2.54	2.62	2.70	2.79	2.87	2.95	3.03	3.13	3.28	3.43	3.60	3.77	3.95	4.25%
UNIONCITY4			1.00	3.10	3.20	3.31	3.43	3.53	3.78	4.03	4.29	4.55	4.69	4.83	4.99	5.13	5.28	5.41	5.59	5.86	6.14	6.43	6.74	7.06	4.25%
Total Feeder Load				10.97	11.31	11.69	12.13	12.48	13.35	14.24	15.15	16.07	16.59	17.06	17.64	18.15	18.67	19.13	19.76	20.71	21.70	22.73	23.82	24.94	-----
Substation Growth Factors					0.031	0.034	0.037	0.029	0.070	0.067	0.064	0.061	0.032	0.028	0.034	0.029	0.029	0.024	0.033	0.048	0.048	0.048	0.048	0.047	-----
Substation Coincident Factor				99.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
VAN METER	8.3	Transformer	1.00	3.56	3.64	3.72	3.81	3.89	4.07	4.25	4.43	4.61	4.71	4.80	4.91	5.00	5.10	5.18	5.29	5.46	5.64	5.82	6.00	6.19	2.84%
VANMTR1			1.00	0.30	0.31	0.32	0.33	0.33	0.35	0.36	0.38	0.39	0.40	0.41	0.42	0.43	0.43	0.44	0.45	0.47	0.48	0.50	0.51	0.53	2.84%
VANMTR2			1.00	0.33	0.34	0.35	0.36	0.36	0.38	0.40	0.41	0.43	0.44	0.45	0.46	0.47	0.48	0.48	0.49	0.51	0.53	0.54	0.56	0.58	2.84%
VANMTR3			1.00	2.93	2.99	3.06	3.13	3.19	3.34	3.49	3.64	3.79	3.87	3.94	4.03	4.11	4.18	4.25	4.35	4.49	4.63	4.78	4.93	5.08	2.84%
Total Feeder Load				3.56	3.64	3.72	3.81	3.89	4.07	4.25	4.43	4.61	4.71	4.80	4.91	5.00	5.10	5.18	5.29	5.46	5.64	5.82	6.00	6.19	-----
Substation Growth Factors					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
Substation Coincident Factor				100.03%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----
COINCIDENT SYSTEM PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	-----
TOT. NON-COINCIDENT SUB. PEAK				133.34	135.80	138.50	141.50	143.90	149.78	155.66	161.54	167.40	170.60	173.50	177.00	180.10	183.20	185.90	189.60	195.10	200.76	206.58	212.57	218.74	-----
SYSTEM GROWTH FACTORS					0.021	0.023	0.025	0.019	0.046	0.044	0.043	0.041	0.021	0.019	0.022	0.019	0.019	0.016	0.022	0.032	0.032	0.032	0.032	0.032	-----
SYSTEM COINCIDENT FACTOR				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	-----

Notes: (1) Historical system coincident and substation non-coincident peak loads provided by Clark Energy
(2) Projected coincident system peak from adjusted 2008 EKPC Load Forecast.

Exhibit 3
AMR/AMI, Radio & Hwy 801
Cost Details

Clark Energy Cooperative RUS Code 705-1 AMR/AMI

Substation	Transf/MVA	Voltage	Circuits / Feeders	EKPC Substation Labor	Estimated Clark Labor	Substation Optimization and Commissioning	TS2 Equipment Enclosure and Hardware	Clark Injection Transformers	Station TCU	SPU 3000 Price Each	Fiber Blades	TS-1 Blade	Total $
Blevins Valley	4.4	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Bowen	5.5	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Cave Run	1.8	69kV	2	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 2,500	$ 2,500	$47,800
Clay City	13.6	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 7,500	$ 2,500	$59,600
Frenchburg	11.1	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 7,500	$ 2,500	$52,800
Hardwicks Creek	13.6	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 5,000	$ 2,500	$57,100
Highrock	0.9	69kV	1	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 2,500	$ 2,500	$47,800
Hinkston	13.6	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 7,500	$ 2,500	$59,600
Hope	13.6	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 5,000	$ 2,500	$57,100
Hunt	13.6	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 7,500	$ 2,500	$59,600
Jeffersonville	11.1	69kV	2	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Mariba	5.5	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 7,500	$ 2,500	$52,800
Miller Hunt	11.1	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Mt. Sterling	11.1	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Reid Village	5.5	69kV	2	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 2,500	$ 2,500	$47,800
Sideveiw	6.3	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 7,500	$ 2,500	$52,800
Stanton	19.5	69kV	5	$5,000	$5,000	$5,000	$2,500	$5,500	$13,600	$13,000	$ 10,000	$ 2,500	$62,100
Three Forks	11.9	138kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Trapp	4.4	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Treehaven	4.4	69kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 7,500	$ 2,500	$52,800
Union City	11.9	138kV	4	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 7,500	$ 2,500	$52,800
Van Meter	6.3	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Jones Nursery	11.9	138kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Indian Fields	5.5	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Stone Road	5.5	69kV	3	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
Korea	5.5	69kV	2	$5,000	$5,000	$5,000	$2,500	$5,500	$6,800	$13,000	$ 5,000	$ 2,500	$50,300
			82	$130,000	$130,000	$130,000	$65,000	$143,000	$217,600	$338,000	$147,500	$65,000	$1,366,100

Estimated Equipment Cost	$1,366,100
TS2 Software upgrade	$15,800
Estimated TS2 Project	1,381,900
Estimated Inflated Cost	1,559,800

Radio Communications

RUS Code 615-1

Description	Cost
• Truck Equipment Mobile units for Fleet	$75,000
• Control Stations Office units	$35,000
• Handheld Equipment Handheld Mobile Units	$30,000
• System Integration Setup\Programming\Training	$40,000
• Tower Installed Equipment Equipment for Existing Tower Locations	$100,000
• Radio Server Computer Hardware\Software\License	$50,000
• Infrastructure Additions New Towers and Repeaters	$215,000
Estimated Project Cost:	**$545,000**

RUS Code 611- Hwy 801

Clark Energy Hazard Mitigation Project
Three Phase Overhead to Three Phase Underground
Cave Run Lake\Daniel Boone National Forest

Item	Quantity	Per Unit Cost	Item Subtotal
Existing Facilities Removal Labor			
Existing Overhead Removal in Feet	17,000	$2.43	$41,310.00
Repair of Mechanical Damage to Forest Service Property			$5,000.00
Material			
1/0 Primary Cable (33489 linear ft + 10% termination)	36,837	$2.36	$86,935.32
Grounding	25	$12.89	$322.25
Load Break Elbows	150	$39.93	$5,989.50
Surge Arrester Elbow	9	$131.18	$1,180.62
Load Break Junctions	75	$172.90	$12,967.50
Three Phase Cabinet	25	$747.88	$18,697.00
Three Phase Fused Sectionalizing Cabinet	1	$3,800.00	$3,800.00
New Facilities Installation Labor			
Boring\trenching of cable	11,163	$26.00	$290,238.00
Clark Energy Labor			
Design\Cable Termination			$25,000.00
Total Estimated Project Cost			$491,440.19
Total Estimated Inflated Cost			$526,400.00

Exhibit 4
Cost of Losses

All information in BLUE text requires input data

LOAD LOSS CALCULATION

ANNUAL COST OF LOSS PER kW:

Cost for Demand:	1kW*DR*DF	$0.00 /kW
Cost for Energy:	(.84(LF^2) + .16(LF))*1kW*(ER)*8760 hours	$122.91 /kW

DR = Existing Power Demand Rate (1)
= $0.00 /kW
LF = Three Year Average Annual Load Factor
= 42.55%
ER = Existing Power Energy Rate (1)
= $0.0637 /kWh
DF = Three Year Average Annual Demand Factor
= 8.10

ANNUAL COST FOR 1kW OF PEAK LOSSES: $122.91 /kW

CORE LOSS CALCULATION

ANNUAL COST OF LOSS PER kW:

Cost for Demand:	1kW*DR*12 months	$0.00 /kW
Cost for Energy	1kW*ER*8760 hours	$558.27 /kW

DR = Existing Power Demand Rate (1)
= $0.00 /kW
ER = Existing Power Energy Rate (1)
= $0.06373 /kWh

ANNUAL COST FOR 1kW OF PEAK LOSSES: $558.27 /kW

LOAD FACTOR CALCULATION (2)

Month	Peak Load (kW) 2006	2007	2008	Three Year Average	Percent of Peak	Percent of Peak Squared
January	91,062	120,288	129,791	113,714	98.28%	0.97
February	107,418	128,287	111,412	115,706	100.00%	1.00
March	93,780	94,981	99,514	96,092	83.05%	0.69
April	73,150	90,814	80,788	81,584	70.51%	0.50
May	81,386	82,356	63,966	75,903	65.60%	0.43
June	87,101	86,331	90,331	87,921	75.99%	0.58
July	96,174	88,461	89,915	91,517	79.09%	0.63
August	96,925	99,175	86,619	94,240	81.45%	0.66
September	68,240	87,477	90,756	82,158	71.01%	0.50
October	82,412	80,118	83,626	82,052	70.91%	0.50
November	90,079	92,855	102,385	95,106	82.20%	0.68
December	112,809	103,604	125,900	114,104	98.62%	0.97
System Peak	112,809	128,287	129,791	115,706	100.00%	8.10
Ann. MWh Purch.	446,178	468,537	463,945	459,553		
Ann. Load Factor	45.15%	41.69%	40.81%	42.55%		

Notes : (1) Based on the annual energy purchases and power cost fı calander year 2008
(2) MWh Purch. and Peak Loading was taken fromForm 7 data

Exhibit 5
Summary of Assumed Fixed Annual Charge Rates

Fixed Cost Assumptions

Interest for Present Worth Analysis	5.00%		

	TRANSMISSION	SUBSTATION	DISTRIBUTION
Annual Inflation on Investment	3.50%	3.50%	3.50%
Depreciation Life of Investment (Years)	40.0	50.0	33.0
Annual Depreciation (3-yr. Avg.)	2.50%	2.00%	3.03%
Nominal Interest Rate	5.00%	5.00%	5.00%
Capital Recovery Factor (Calculated)	5.83%	5.48%	6.25%
Percent O&M Expense of Installed Plant	3.00%	2.00%	4.10%
Annual Inflation of O&M Expenses	0.00%	0.00%	0.00%
Tax on Investment Book Value	0.04%	0.04%	0.04%
Annual Inflation of Tax Rate	0.00%	0.00%	0.00%
Percent Insurance Expense of Installed Plant	0.05%	0.05%	0.05%
Annual Inflation of Insurance Expense	0.00%	0.00%	0.00%

COST OF LOSSES	
Cost for 1kW of Peak Loss (Cu)	$129.24
Cost for 1kW of Peak Loss (Fe)	$587.03
Annual Inflation of Cost of Losses	0.00%

Appendix A
2008 EKPC Load Forecast

Clark Energy Cooperative 2008 Load Forecast

Prepared by:
East Kentucky Power Cooperative, Inc.
Resource Planning Department

June 2008

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Introduction

Executive Summary

Clark Energy Cooperative, (Clark Energy) located in Winchester, Kentucky, is an electric distribution cooperative that serves members in 11 counties. This load forecast report contains Clark Energy long-range forecast of energy and peak demand.

Clark Energy and its power supplier, East Kentucky Power Cooperative (EKPC), worked jointly to prepare the load forecast. Factors considered in preparing the forecast include the national and local economy, population and housing trends, service area industrial development, electric price, household income, weather, and appliance efficiency changes.

EKPC prepared a preliminary load forecast, which was reviewed by Clark Energy for reasonability. Final projections reflect a rigorous analysis of historical data combined with the experience and judgment of the manager and staff of Clark Energy. Key assumptions are reported beginning on page 20.

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Executive Summary *(continued)*

The load forecast is prepared biannually as part of the overall planning cycle at EKPC and Clark Energy. Cooperation helps to ensure that the forecast meets both parties' needs. Clark Energy uses the forecast in developing two-year work plans, long-range work plans, and financial forecasts. EKPC uses the forecast in areas of marketing analysis, transmission planning, generation planning, demand-side planning, and financial forecasting.

The complete load forecast for Clark Energy is reported in Table 1-1. Residential and commercial sales, total purchases, winter and summer peak demands, and load factor are presented for the years 1990 through 2025.

Table 1-1
Clark Energy Cooperative
2008 Load Forecast
MWh Summary

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Other Sales (MWh)	Total Sales (MWh)	Office Use (MWh)	% Loss	Purchased Power (MWh)
1990	161,301	0	54,943	0	716	446	217,406	506	7.6	235,946
1991	169,722	0	57,046	0	122	479	227,369	493	8.2	248,153
1992	172,313	0	58,436	0	1,919	527	233,196	422	7.7	252,997
1993	193,421	0	61,275	0	1,565	596	256,858	456	6.3	274,687
1994	190,886	0	62,591	0	3,728	653	257,858	509	7.0	277,933
1995	204,347	0	66,227	0	6,625	800	278,000	532	6.1	296,611
1996	220,157	0	69,687	0	8,222	1,003	299,069	565	7.3	323,310
1997	223,132	0	71,759	0	5,376	925	301,192	511	6.1	321,396
1998	234,698	0	78,457	0	1,717	605	315,476	498	6.3	337,162
1999	248,859	0	77,390	0	2,050	583	328,882	516	6.8	353,317
2000	264,282	0	78,100	0	9,212	541	352,135	532	5.7	374,001
2001	280,250	0	80,559	0	10,870	534	372,213	508	7.1	401,373
2002	297,277	0	82,632	0	10,726	540	391,175	522	4.8	411,248
2003	297,031	0	86,523	0	8,364	538	392,455	541	6.0	418,275
2004	304,332	0	88,922	0	8,173	560	401,986	588	5.9	427,871
2005	327,283	0	91,761	0	9,095	636	428,774	539	4.6	449,841
2006	317,021	0	86,096	0	16,391	649	420,158	659	5.7	446,178
2007	336,749	0	91,533	0	15,477	645	444,403	788	5.0	468,537
2008	339,194	0	92,297	0	13,830	661	445,982	788	5.0	470,284
2009	354,521	0	95,115	0	14,012	658	464,306	788	5.0	489,574
2010	362,555	0	97,459	0	14,279	657	474,951	788	5.0	500,778
2011	368,857	0	99,534	0	14,537	657	483,586	788	5.0	509,868
2012	377,434	0	101,213	0	14,749	658	494,055	788	5.0	520,887
2013	384,002	0	102,694	0	14,937	660	502,293	788	5.0	529,560
2014	390,547	0	104,068	0	15,111	662	510,387	788	5.0	538,080
2015	399,067	0	105,438	0	15,284	664	520,454	788	5.0	548,676
2016	408,127	0	106,744	0	15,450	667	530,988	788	5.0	559,764
2017	416,100	0	107,981	0	15,607	669	540,357	788	5.0	569,627
2018	423,793	0	109,135	0	15,753	671	549,353	788	5.0	579,096
2019	432,936	0	110,001	0	15,863	674	559,473	788	5.0	589,749
2020	442,543	0	110,910	0	15,978	676	570,107	788	5.0	600,943
2021	450,473	0	111,831	0	16,095	679	579,078	788	5.0	610,386
2022	459,101	0	112,830	0	16,221	681	588,834	788	5.0	620,655
2023	467,758	0	113,800	0	16,344	684	598,587	788	5.0	630,921
2024	476,707	0	114,853	0	16,478	686	608,723	788	5.0	641,591
2025	485,543	0	115,861	0	16,605	688	618,698	788	5.0	652,091
2026	494,759	0	116,900	0	25,001	691	637,351	788	5.0	671,726
2027	503,914	0	117,889	0	25,127	693	647,623	788	5.0	682,538

Table 1-1 (continued)
Clark Energy Cooperative
Load Forecast Study
Peaks Summary

Winter		*Summer*				
Season	Noncoincident Peak Demand (MW)	Year	Noncoincident Peak Demand (MW)	Year	Purchased Power (MWh)	Load Factor (%)
1989 - 90	64.0	1990	51.1	1990	235,946	42.1%
1990 - 91	57.9	1991	54.5	1991	248,153	48.9%
1991 - 92	59.9	1992	52.1	1992	252,997	48.2%
1992 - 93	63.5	1993	60.0	1993	274,687	49.4%
1993 - 94	77.0	1994	59.0	1994	277,933	41.2%
1994 - 95	68.0	1995	65.0	1995	296,611	49.8%
1995 - 96	79.8	1996	66.8	1996	323,310	46.2%
1996 - 97	80.1	1997	70.3	1997	321,396	45.8%
1997 - 98	72.8	1998	73.5	1998	337,162	52.4%
1998 - 99	87.3	1999	82.4	1999	353,317	46.2%
1999 - 00	94.5	2000	81.9	2000	374,001	45.2%
2000 - 01	103.5	2001	84.6	2001	401,373	44.3%
2001 - 02	93.7	2002	88.7	2002	411,248	50.1%
2002 - 03	110.3	2003	86.6	2003	418,275	43.3%
2003 - 04	111.2	2004	85.2	2004	427,871	43.9%
2004 - 05	114.5	2005	94.6	2005	449,841	44.9%
2005 - 06	107.4	2006	96.9	2006	446,178	47.4%
2006 - 07	128.3	2007	99.2	2007	468,537	41.7%
2007 - 08	129.8	2008	98.8	2008	470,284	41.4%
2008 - 09	130.1	2009	102.0	2009	489,574	43.0%
2009 - 10	133.3	2010	104.0	2010	500,778	42.9%
2010 - 11	135.8	2011	105.6	2011	509,868	42.9%
2011 - 12	138.5	2012	107.2	2012	520,887	42.9%
2012 - 13	141.5	2013	108.8	2013	529,560	42.7%
2013 - 14	143.9	2014	110.3	2014	538,080	42.7%
2014 - 15	147.0	2015	112.0	2015	548,676	42.6%
2015- 16	149.7	2016	113.5	2016	559,764	42.7%
2016 - 17	153.0	2017	115.4	2017	569,627	42.5%
2017 - 18	155.7	2018	117.0	2018	579,096	42.4%
2018 - 19	158.8	2019	118.6	2019	589,749	42.4%
2019-20	161.6	2020	120.0	2020	600,943	42.5%
2020-21	164.9	2021	121.8	2021	610,386	42.3%
2021-22	167.8	2022	123.5	2022	620,655	42.2%
2022-23	170.9	2023	125.1	2023	630,921	42.2%
2023-24	173.4	2024	126.5	2024	641,591	42.2%
2024-25	177.0	2025	128.6	2025	652,091	42.1%
2025-26	182.3	2026	133.0	2026	671,726	42.1%
2026-27	185.5	2027	134.8	2027	682,538	42.0%

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Executive Summary *(continued)*

Overall Results

- Total sales are projected to grow by 1.9 percent a year for the period 2007-2027, compared to 2.2 percent which was projected in the 2006 load forecast for the period 2005-2025. Results shown in Table 1-2 and Figure 1-1.
- Winter and summer peak demands for the same period indicate annual growth of 1.8 and 1.6 percent, respectively. Annual peaks shown in Figure 1-2.
- Load factor remains steady at approximately 43% for the forecast period. See Figure 1-3.

Executive Summary

Overall Results *(continued)*

Table 1-2
Clark Energy 2008 Load Forecast
Summary of Sales Growth Rates

	Time Period	Residential	Small Commercial	Large Commercial	Other	Total Sales
	1997-2002	5.9%	2.9%	14.8%	-10.2%	5.4%
	2002-2007	2.5%	2.1%	7.6%	3.6%	2.6%
5 Year Growth Rates	2007-2012	2.3%	2.0%	-1.0%	0.4%	2.1%
	2012-2017	2.0%	1.3%	1.1%	0.3%	1.8%
	2017-2022	2.0%	0.9%	0.8%	0.4%	1.7%
	2022-2027	1.9%	0.9%	9.1%	0.3%	1.9%
	1997-2007	4.2%	2.5%	11.2%	-3.5%	4.0%
10 Year Growth Rates	2007-2017	2.1%	1.7%	0.1%	0.4%	2.0%
	2017-2027	1.9%	0.9%	4.9%	0.4%	1.8%

Figure 1-1
Average Annual Growth in Sales
2007-2027

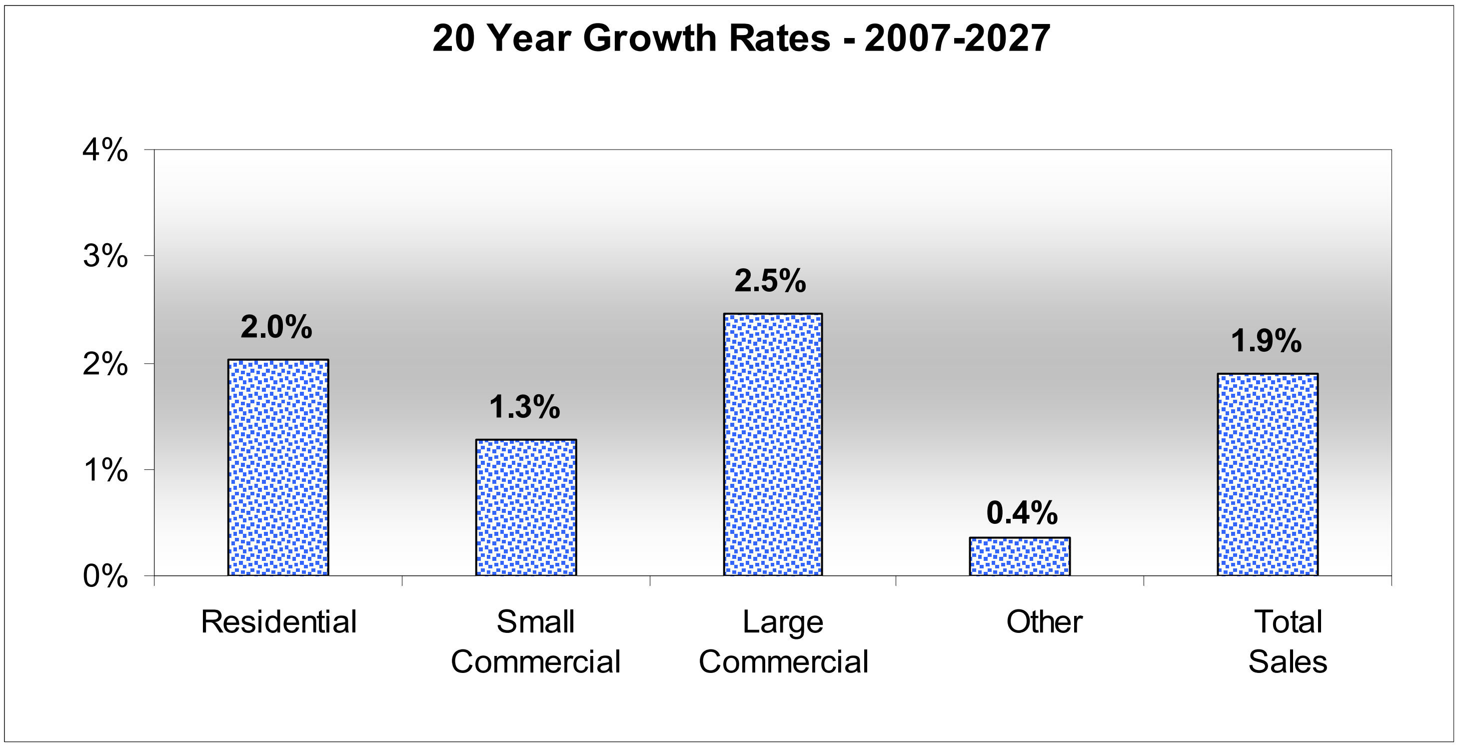


Figure 1-2
Peak Demand Forecast
Winter and Summer

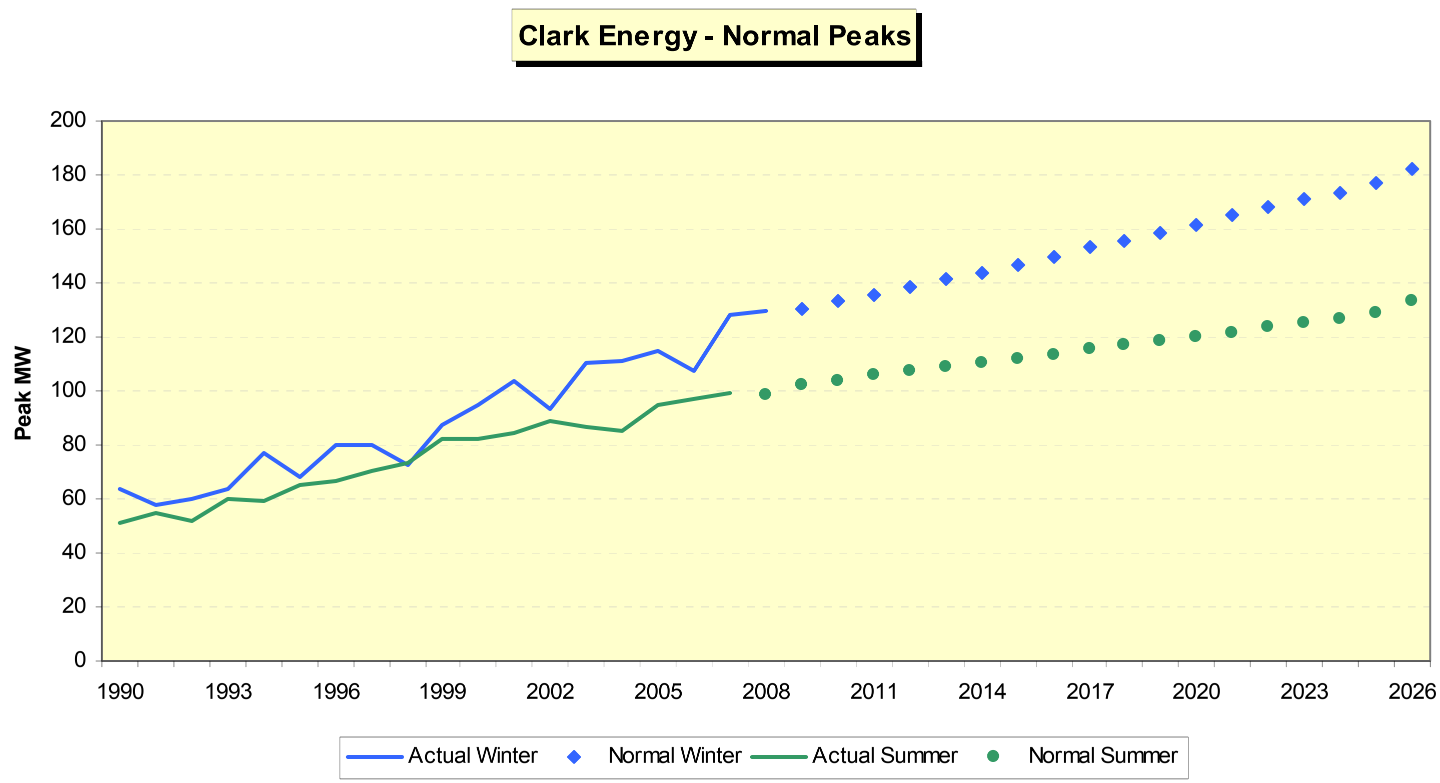
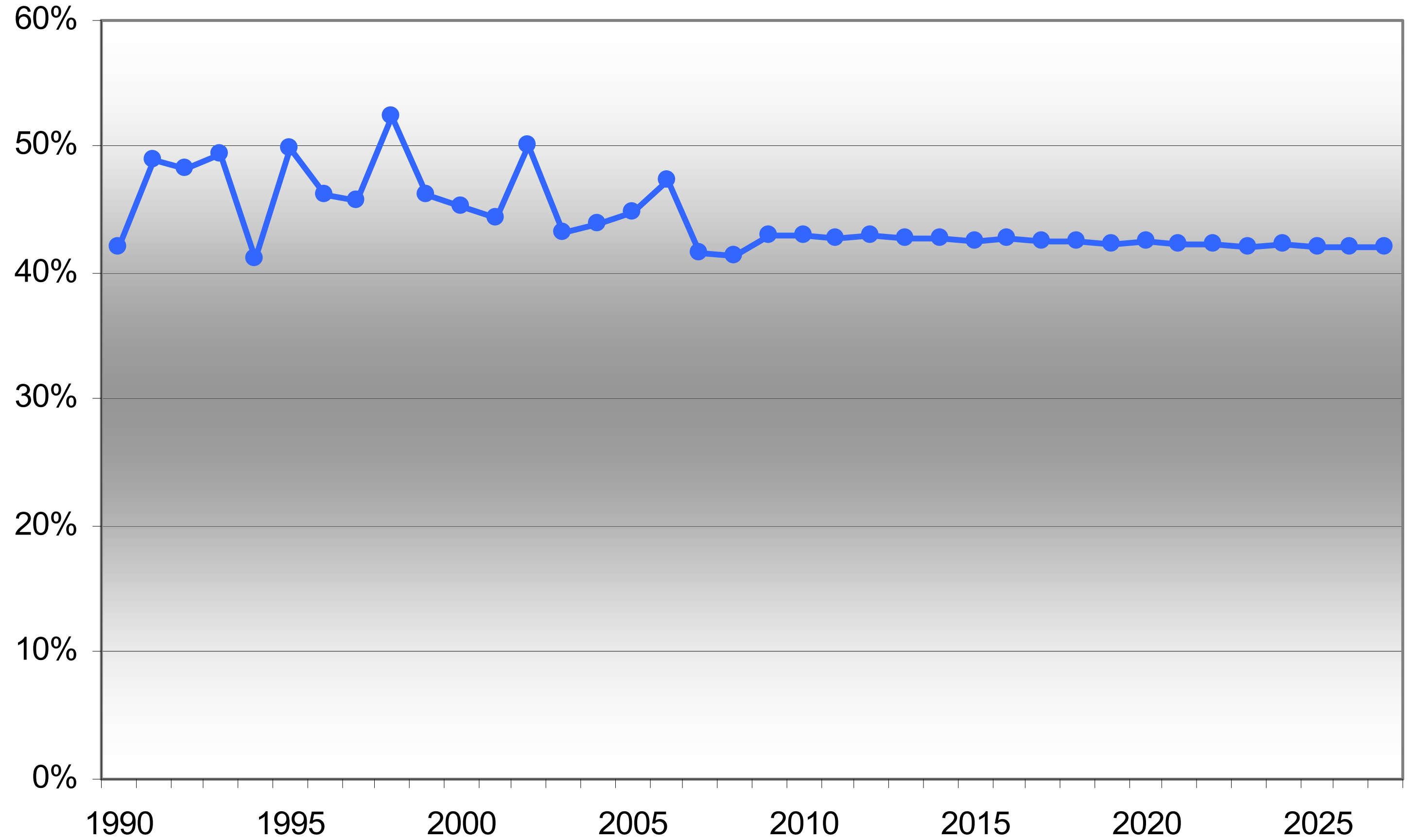


Figure 1-3
Annual System Load Factor



Narrative

Clark Energy provides electric service within areas of central and east central Kentucky. The service area extends east from the Lexington metropolitan and bluegrass regions, west of the corporate headquarters location in Winchester, to the foothill areas adjacent to the mountainous regions of Eastern Kentucky.

Clark Energy predominantly serves members within the counties of Clark, Montgomery, Bath, Menifee, Powell, Madison, and Bourbon. Portions of the counties of Fayette, Rowan, Morgan, Wolfe, and Estill are also served by Clark Energy.

No corporate annexations, mergers, or legislation pertaining to certification of territory possibly altering the complexion of the service area is anticipated.

Narrative *(continued)*

The potential for continued economic development within Clark Energy's service area exists due to a variety of factors. Access to major surface transportation systems contributes to development throughout the Lexington metropolitan region. Convenient transportation for goods and services is available throughout a majority of the service area. Major surface transportation within the area consists of two major interstate highways and a major state parkway.

Established industrial parks provide attractive facilities for additional commercial activity. The existence of two state parks along with other recreational resources affords some opportunities for possible future development. Economic development within the eastern counties of Bath, Menifee, and Rowan consists primarily of commercial timber and agricultural operations. The western and southwestern counties close to or part of the metropolitan Lexington area offers the greatest potential for economic growth. These counties, which possess the majority of residential, industrial, and commercial members served, include Clark, Montgomery, Powell, Madison, Bourbon, and Fayette.

Narrative *(continued)*

Clark Energy Members Demographic Information

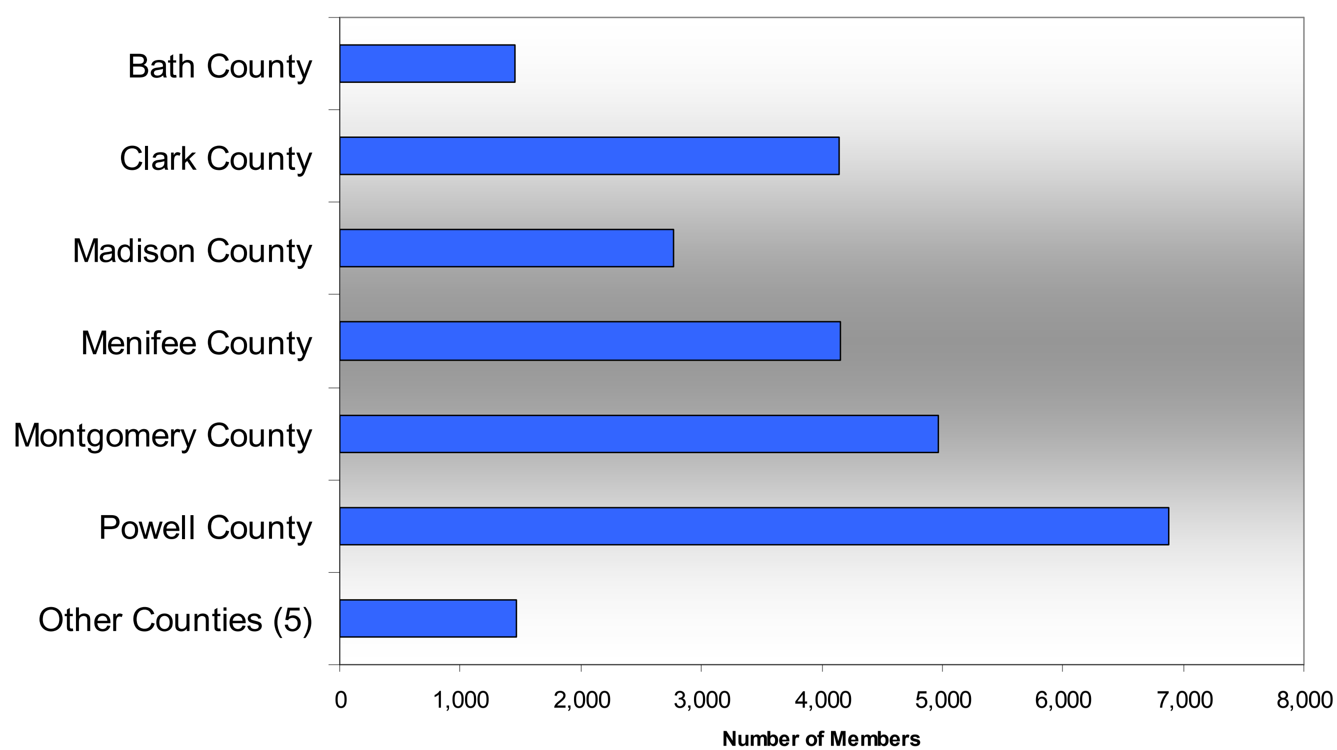
- There is an average of 2.45 people per household.
- 58% of all homes are headed by someone age 55 or greater.
- Approximately 25% of homes have farm operations, with beef cattle most prevalent.
- Nearly 26% of all homes served are less than 10 years old.

Narrative *(continued)*

Counties Served

Clark Energy provides service to members in 11 counties.

Figure 1-4



Key Assumptions
Power Cost and Rates

- EKPC's wholesale power cost forecast used in this load forecast comes from the following report: "Twenty-Year Financial Forecast and Equity Development Plan, 2008-2027", revised February 12, 2008.

- Average residential retail rates will change from 8.825 cents/kWh in 2007 to 10.779 cents/kWh in 2027.

Key Assumptions *(continued)*
North Eastern Economic Region History and Forecast~

	Population		Households		Total Employment		Unemployment Rate		Regional Total Income	
		(%) Change		(%) Change		(%) Change		(%) Change		(%) Change
1990	250,788		93,007		77,606		8.8%		$3,202	
1991	252,745	0.8%	94,963	2.1%	77,933	0.4%	10.1%	14.9%	$3,350	4.6%
1992	254,920	0.9%	96,280	1.4%	80,026	2.7%	10.9%	8.5%	$3,617	8.0%
1993	256,441	0.6%	97,016	0.8%	79,646	-0.5%	9.8%	-10.0%	$3,655	1.0%
1994	257,720	0.5%	97,903	0.9%	82,076	3.1%	7.8%	-20.8%	$3,837	5.0%
1995	258,925	0.5%	99,365	1.5%	83,736	2.0%	7.6%	-2.2%	$3,953	3.0%
1996	260,247	0.5%	100,637	1.3%	85,337	1.9%	7.4%	-3.2%	$4,135	4.6%
1997	261,862	0.6%	101,597	1.0%	87,340	2.3%	6.8%	-7.6%	$4,439	7.4%
1998	263,275	0.5%	102,482	0.9%	89,226	2.2%	6.1%	-11.3%	$4,652	4.8%
1999	264,646	0.5%	103,428	0.9%	89,974	0.8%	5.6%	-7.0%	$4,670	0.4%
2000	265,827	0.4%	104,065	0.6%	91,175	1.3%	5.6%	-0.7%	$5,137	10.0%
2001	266,848	0.4%	104,726	0.6%	91,026	-0.2%	7.4%	31.9%	$5,205	1.3%
2002	267,719	0.3%	105,193	0.4%	93,013	2.2%	6.4%	-13.0%	$5,394	3.6%
2003	268,535	0.3%	105,700	0.5%	93,346	0.4%	7.0%	9.6%	$5,533	2.6%
2004	269,496	0.4%	106,200	0.5%	93,975	0.7%	6.4%	-8.7%	$5,662	2.3%
2005	271,167	0.6%	106,823	0.6%	94,748	0.8%	6.6%	3.4%	$6,046	6.8%
2006	272,821	0.6%	107,542	0.7%	94,664	-0.1%	5.8%	-12.2%	$6,384	5.6%
2007	274,159	0.5%	108,187	0.6%	94,713	0.1%	6.1%	3.9%	$6,734	5.5%
2008	275,813	0.6%	109,039	0.8%	95,785	1.1%	6.2%	2.2%	$6,970	3.5%
2009	277,129	0.5%	109,812	0.7%	97,258	1.5%	6.2%	-0.3%	$7,208	3.4%
2010	278,308	0.4%	110,569	0.7%	98,606	1.4%	6.1%	-1.1%	$7,536	4.5%
2011	279,448	0.4%	111,256	0.6%	99,960	1.4%	6.3%	3.0%	$7,842	4.1%
2012	280,611	0.4%	111,894	0.6%	101,098	1.1%	5.8%	-7.5%	$8,230	5.0%
2017	287,249	0.4%	115,271	0.4%	106,040	0.7%	5.9%	0.2%	$10,177	3.1%
2027	296,650	0.3%	119,752	0.4%	113,547	0.7%	6.1%	0.4%	$15,356	4.2%

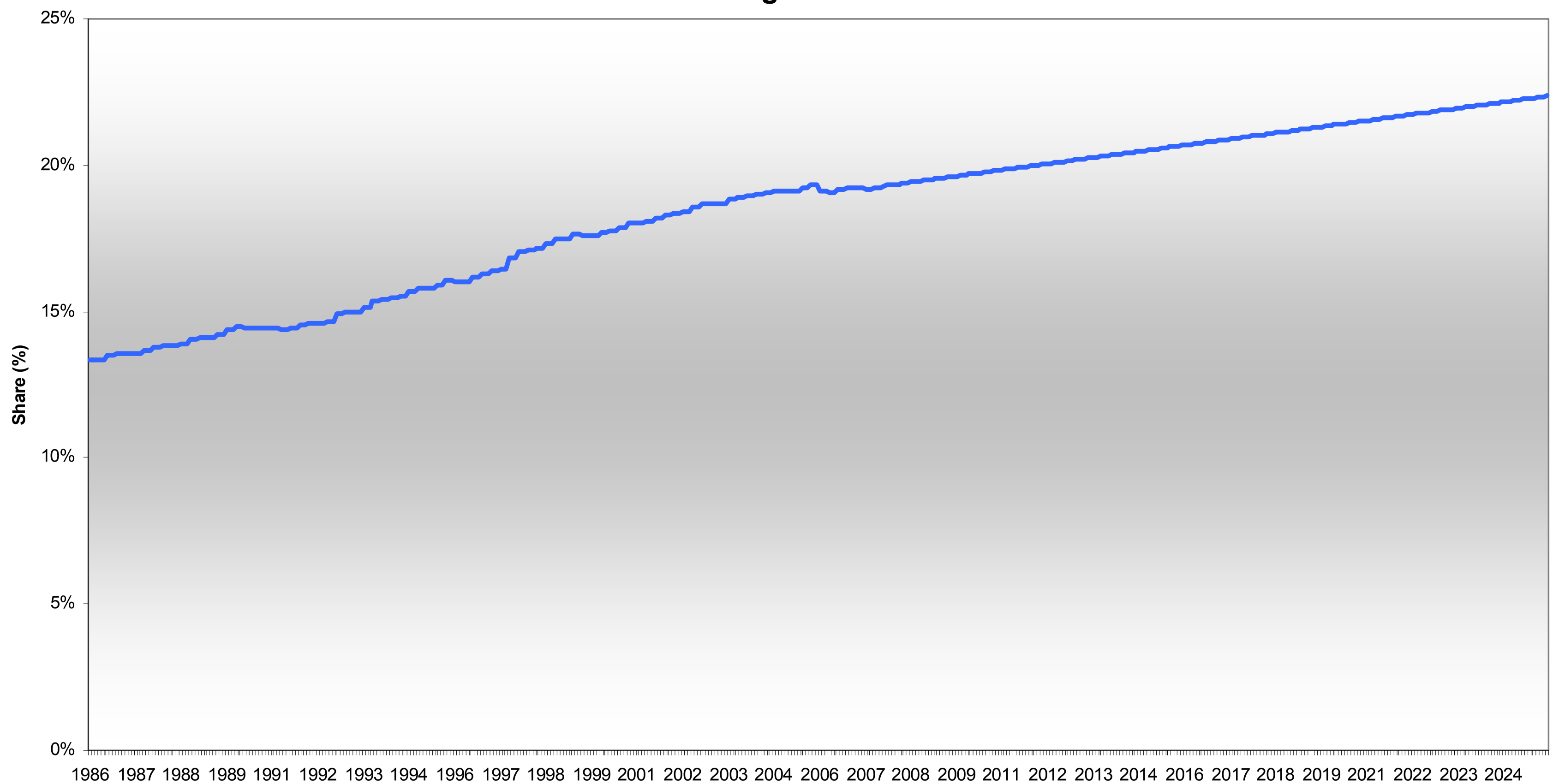
EKPC's source for economic forecasts is Global Insight. Regional Income is reported in millions of 2007 dollars. Growth rates are average annual changes.

Key Assumptions *(continued)*

Share of Regional Homes Served

Clark Energy's market share will increase for the forecast period.

Figure 1-5

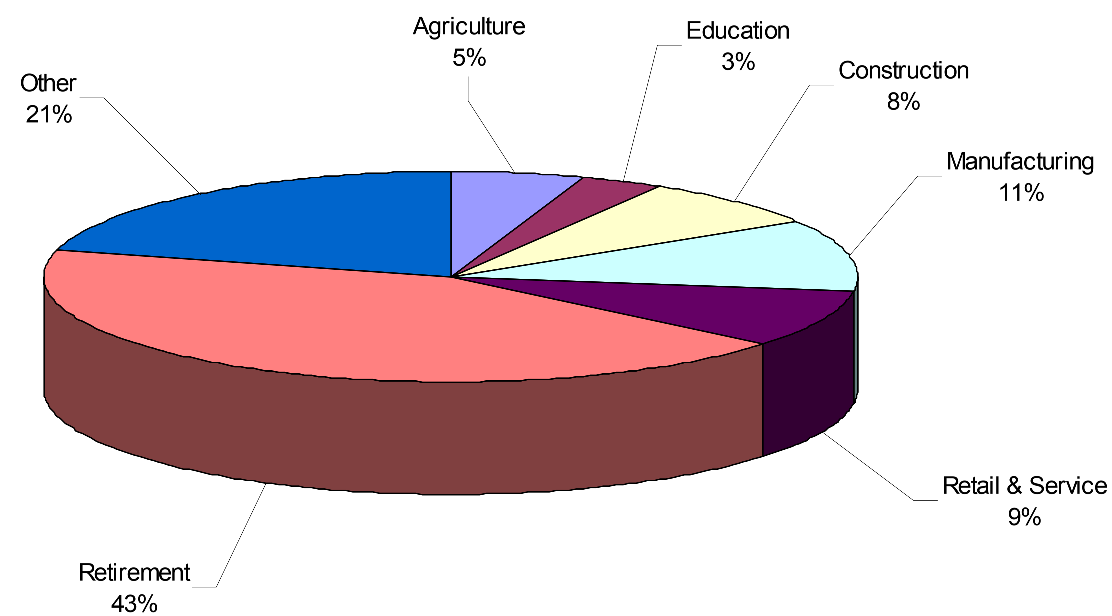


Key Assumptions *(continued)*

Household Income

Members' Greatest Sources

Figure 1-6



Key Assumptions *(continued)*

Appliance Saturations

- All electric heat saturation will increase from 52 percent to approximately 61 percent.
- Central air conditioning will continue its penetration into the service area with approximately 74 percent of all residences having central air by 2027.
- Room air conditioner saturation is declining due to customers choosing central air conditioning systems.
- Electric water heater saturation will increase slightly to approximately 87 percent.
- Appliance efficiency trends are accounted for in the model. The data is collected from Energy Information Administration, (EIA). See Figure 1-7.

Key Assumptions *(continued)*

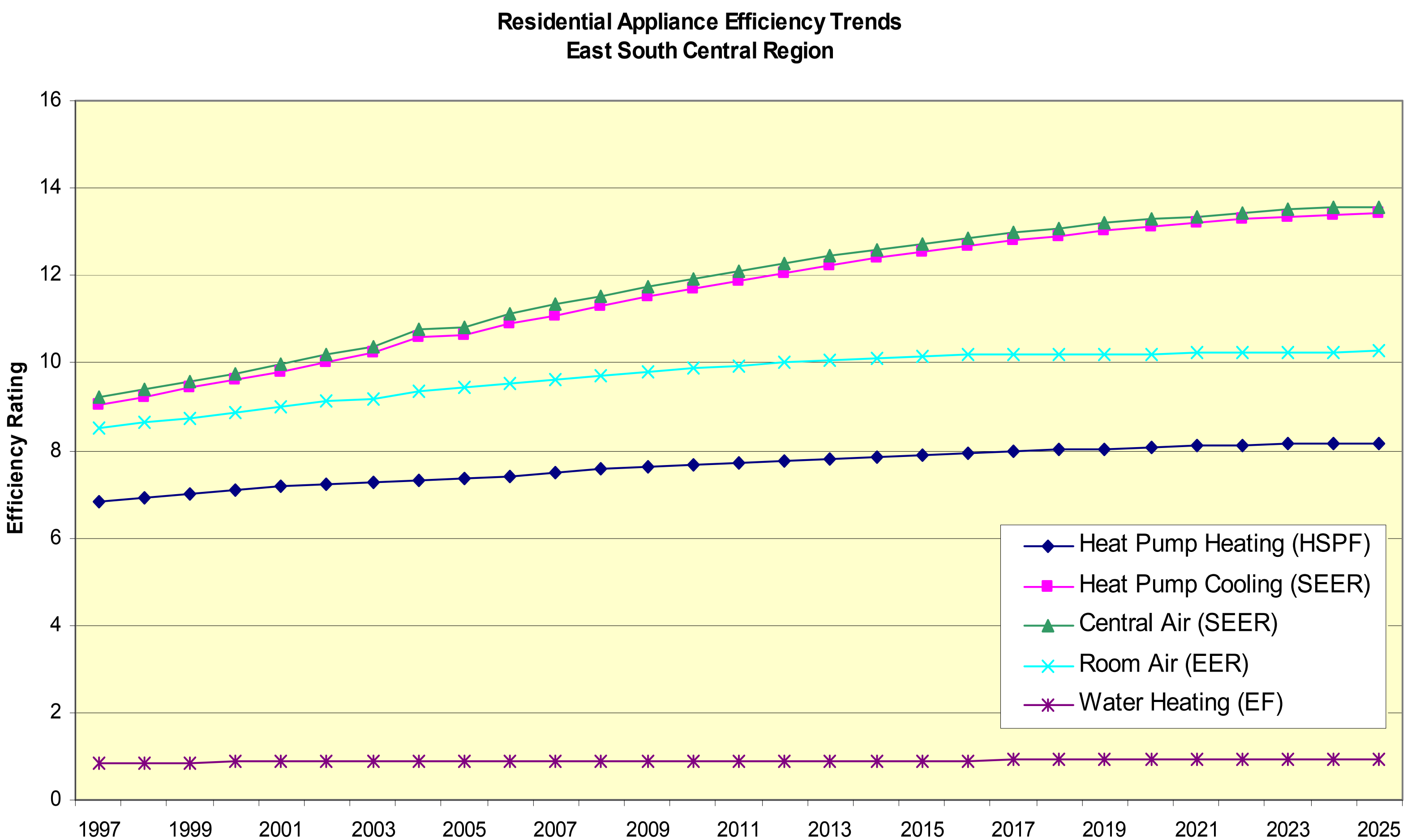
Saturation Rates

Non HVAC Appliances

Microwave Oven	97%
Electric Range	91%
Dishwasher	47%
Freezer	71%
Clothes Dryer	94%
Personal Computer	57%

Key Assumptions *(continued)*

Figure 1-7



Source: Energy Information Administration (EIA) Efficiency Trend Update, 2007

Key Assumptions *(continued)*

Weather

- Weather data is from the Lexington weather station.
- Normal weather, a 30-year average of historical temperatures, is assumed for the forecast years.

Methodology and Results

Introduction

This section briefly describes the methodology used to develop the load forecast and presents results in tabular and graphical form for residential and commercial classifications. Table 1-3 through Table 1-5 shows historical data for Clark Energy as reported on RUS Form 736 and RUS Form 5.

A preliminary forecast is prepared during the first quarter depending on when Clark Energy experiences its winter peak. The first step is modeling the regional economy. Population, income, and employment are among the areas analyzed. The regional model results are used in combination with the historical billing information, appliance saturation data, appliance efficiency data, and weather data to develop the long range forecast.

Table 1-3

Clark Energy Comparative Annual Operating Data

Year	kWh Purchased And Generated	Change	kWh Sold	Change	kWh Loss	% Loss	Peak Demand (MW)	Annual Load Factor	Average Number Of Consumers	Miles Of Line	Consumers Per Mile	Cost Of Purchased Power	Cents / kWh
1995	296,610,666		278,000,056		18,078,761	6.1%	65.8	51.5%	19,743	2,563	7.7	$10,648,936	3.6
1996	323,309,929	9.0%	299,068,767	7.6%	23,675,682	7.3%	76.4	48.3%	20,364	2,597	7.8	$10,831,006	3.4
1997	321,395,538	-0.6%	301,191,966	0.7%	19,692,481	6.1%	78.1	47.0%	21,138	2,638	8.0	$10,809,438	3.4
1998	337,161,610	4.9%	315,476,279	4.7%	21,187,571	6.3%	68.8	55.9%	21,900	2,675	8.2	$11,372,602	3.4
1999	353,317,035	4.8%	328,782,300	4.2%	24,018,252	6.8%	84.6	47.7%	22,464	2,716	8.3	$12,475,362	3.5
2000	374,000,670	5.9%	352,135,176	7.1%	21,332,863	5.7%	90.2	47.4%	22,917	2,754	8.3	$13,688,455	3.7
2001	401,372,636	7.3%	372,212,600	5.7%	28,652,147	7.1%	96.7	47.4%	23,427	2,805	8.4	$15,647,642	3.9
2002	411,248,443	2.5%	391,174,774	5.1%	19,550,946	4.8%	89.8	52.3%	23,977	2,845	8.4	$15,962,943	3.9
2003	418,274,586	1.7%	392,455,064	0.3%	25,278,488	6.0%	107.1	44.6%	24,376	2,865	8.5	$16,688,715	4.0
2004	427,871,274	2.3%	401,986,359	2.4%	25,296,918	5.9%	105.9	46.1%	24,796	2,900	8.6	$18,688,571	4.4
2005	449,841,288	5.1%	428,774,102	6.7%	20,527,748	4.6%	111.1	46.2%	25,151	2,935	8.6	$23,109,319	5.1
2006	446,178,468	-0.8%	420,157,719	-2.0%	25,361,286	5.7%	106.3	47.9%	25,508	2,966	8.6	$25,030,997	5.6
2007	468,537,052	5.0%	444,403,153	5.8%	23,345,426	5.0%	120.9	44.2%	25,801	2,982	8.7	$27,894,967	6.0
Average						5.9%							4.2

Table 1-4

Clark Energy Comparative Annual Operating Data

Year	Residential kWh Sales	Residential % Change	Residential Seasonal kWh Sales	Residential Seasonal % Change	Commercial / Industrial (1 MW Or Less) kWh Sales	Commercial / Industrial (1 MW Or Less) % Change	Commercial / Industrial (Over 1 MW) kWh Sales	Commercial / Industrial (Over 1 MW) % Change	Public Street / Highway Lighting kWh Sales	Public Street / Highway Lighting % Change	Public Authorities kWh Sales	Public Authorities % Change
1995	204,347,463		0		66,227,303		6,625,456		799,834		0	
1996	220,156,696	7.7%	0		69,687,175	5.2%	8,221,978	24.1%	1,002,918	25.4%	0	
1997	223,132,166	1.4%	0		71,758,852	3.0%	5,375,903	-34.6%	925,045	-7.8%	0	
1998	234,697,552	5.2%	0		78,456,911	9.3%	1,717,289	-68.1%	604,527	-34.6%	0	
1999	248,759,223	6.0%	0		77,390,324	-1.4%	2,049,522	19.3%	583,231	-3.5%	0	
2000	264,282,445	6.2%	0		78,100,031	0.9%	9,212,072	349.5%	540,628	-7.3%	0	
2001	280,249,670	6.0%	0		80,558,908	3.1%	10,870,142	18.0%	533,880	-1.2%	0	
2002	297,277,346	6.1%	0		82,631,722	2.6%	10,725,827	-1.3%	539,879	1.1%	0	
2003	297,030,797	-0.1%	0		86,522,802	4.7%	8,363,729	-22.0%	537,736	-0.4%	0	
2004	304,332,144	2.5%	0		88,921,610	2.8%	8,172,658	-2.3%	559,947	4.1%	0	
2005	327,283,225	7.5%	0		91,760,571	3.2%	9,094,782	11.3%	635,524	13.5%	0	
2006	317,021,099	-3.1%	0		86,096,015	-6.2%	16,391,240	80.2%	649,365	2.2%	0	
2007	336,749,057	6.2%	0		91,532,612	6.3%	15,476,617	-5.6%	644,867	-0.7%	0	
Average Annual Change												
2 Year	4,732,916	1.4%			-113,980	-0.1%	3,190,918	30.4%	4,672	0.7%		
5 Year	7,894,342	2.5%			1,780,178	2.1%	950,158	7.6%	20,998	3.6%		
10 Year	11,361,689	4.2%			1,977,376	2.5%	1,010,071	11.2%	-28,018	-3.5%		

Table 1-5

Clark Energy Comparative Annual Operating Data

	Residential		Residential Seasonal		Commercial / Industrial (1 MW Or Less)		Commercial / Industrial (Over 1 MW)		Public Street / Highway Lighting		Public Authorities	
Year	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.
1995	18,474	922	0		1,164	4,741	1	552,121	104	641	0	
1996	18,988	966	0		1,210	4,799	2	342,582	164	510	0	
1997	19,768	941	0		1,235	4,842	1	447,992	134	575	0	
1998	20,622	948	0		1,260	5,189	0	#DIV/0!	18	2,799	0	
1999	21,153	980	0		1,291	4,996	1	170,794	19	2,558	0	
2000	21,567	1,021	0		1,328	4,901	1	767,673	21	2,145	0	
2001	22,041	1,060	0		1,363	4,925	1	905,845	22	2,022	0	
2002	22,555	1,098	0		1,400	4,919	1	893,819	21	2,142	0	
2003	22,939	1,079	0		1,414	5,099	2	348,489	21	2,134	0	
2004	23,306	1,088	0		1,466	5,055	1	681,055	23	2,029	0	
2005	23,561	1,158	0		1,562	4,895	1	757,899	27	1,961	0	
2006	23,868	1,107	0		1,608	4,462	3	455,312	29	1,866	0	
2007	24,152	1,162	0		1,615	4,723	3	429,906	31	1,734	0	
10 Year Avg	438	22			38	-12	0	-1,809	-10	116		
5 Year Avg	319	13			43	-39	0	-92,783	2	-82		
2 Year Avg	296	2			27	-86	1	-163,996	2	-114		

Annual Changes In Clark Energy's Residential Class

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*
Consumers	514	780	854	531	414	474	514	384	367	255	307	284
kWh/month	44	-26	8	32	41	38	39	-19	9	69	-51	55

Methodology and Results *(continued)*

The preliminary forecast was presented to Clark Energy staff, and reviewed by the Rural Utilities Services (RUS) Field Representative. Changes were made to the forecast as needed based on new information, such as new large loads or subdivisions. In some instances, other assumptions were changed based on insights from Clark Energy staff. Input from EKPC and Clark Energy results in the best possible forecast.

Methodology and Results *(continued)*

Residential Forecast

Residential customers are analyzed by means of regression analysis with resulting coefficients used to prepare customer projections. Regressions for residential customers are typically a function of regional economic and demographic variables. Two variables that are very significant are the numbers of households by county in each member system's economic region and the percent of total households served by the member system. Table 1-6 and Figure 1-8 report Clark Energy’s customer forecast.

The residential energy sales were projected using a statistically adjusted end-use (SAE) approach. This method of modeling incorporates end-use forecasts and can be used to allocate the monthly and annual forecasts into end-use components. This method, like end-use modeling, requires detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information. The SAE approach segments the average household use into heating, cooling, and water heating end-use components. See Figure 1-9. This model accounts for appliance efficiency improvements. Table 1-6 reports Clark Energy’s energy forecast.

Table 1-6

Clark Energy Cooperative
2008 Load Forecast
Residential Summary

	Customers			*Use Per Customer*			*Class Sales*		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	15,837			849			161,301		
1991	16,157	320	2.0	875	27	3.1	169,722	8,421	5.2
1992	16,726	569	3.5	859	-17	-1.9	172,313	2,591	1.5
1993	17,272	546	3.3	933	75	8.7	193,421	21,108	12.2
1994	17,828	556	3.2	892	-41	-4.4	190,886	-2,535	-1.3
1995	18,474	646	3.6	922	30	3.3	204,347	13,461	7.1
1996	18,988	514	2.8	966	44	4.8	220,157	15,809	7.7
1997	19,768	780	4.1	941	-26	-2.6	223,132	2,975	1.4
1998	20,622	854	4.3	948	8	0.8	234,698	11,565	5.2
1999	21,153	531	2.6	980	32	3.4	248,859	14,162	6.0
2000	21,567	414	2.0	1,021	41	4.2	264,282	15,423	6.2
2001	22,043	476	2.2	1,059	38	3.8	280,250	15,967	6.0
2002	22,555	512	2.3	1,098	39	3.7	297,277	17,028	6.1
2003	22,939	384	1.7	1,079	-19	-1.8	297,031	-247	-0.1
2004	23,306	367	1.6	1,088	9	0.8	304,332	7,301	2.5
2005	23,561	255	1.1	1,158	69	6.4	327,283	22,951	7.5
2006	23,868	307	1.3	1,107	-51	-4.4	317,021	-10,262	-3.1
2007	24,152	284	1.2	1,162	55	5.0	336,749	19,728	6.2
2008	24,412	260	1.1	1,158	-4	-0.3	339,194	2,445	0.7
2009	24,785	373	1.5	1,192	34	2.9	354,521	15,327	4.5
2010	25,154	369	1.5	1,201	9	0.8	362,555	8,034	2.3
2011	25,518	364	1.4	1,205	3	0.3	368,857	6,302	1.7
2012	25,873	355	1.4	1,216	11	0.9	377,434	8,576	2.3
2013	26,225	352	1.4	1,220	5	0.4	384,002	6,569	1.7
2014	26,589	364	1.4	1,224	4	0.3	390,547	6,544	1.7
2015	26,954	365	1.4	1,234	10	0.8	399,067	8,520	2.2
2016	27,322	368	1.4	1,245	11	0.9	408,127	9,060	2.3
2017	27,689	367	1.3	1,252	7	0.6	416,100	7,973	2.0
2018	28,038	349	1.3	1,260	7	0.6	423,793	7,693	1.8
2019	28,384	346	1.2	1,271	11	0.9	432,936	9,143	2.2
2020	28,722	338	1.2	1,284	13	1.0	442,543	9,608	2.2
2021	29,033	311	1.1	1,293	9	0.7	450,473	7,930	1.8
2022	29,358	325	1.1	1,303	10	0.8	459,101	8,627	1.9
2023	29,678	320	1.1	1,313	10	0.8	467,758	8,658	1.9
2024	30,004	326	1.1	1,324	11	0.8	476,707	8,948	1.9
2025	30,316	312	1.0	1,335	11	0.8	485,543	8,836	1.9
2026	30,648	332	1.1	1,345	11	0.8	494,759	9,216	1.9
2027	30,965	317	1.0	1,356	11	0.8	503,914	9,155	1.9

Figure 1-8
Annual Change in Residential Customers

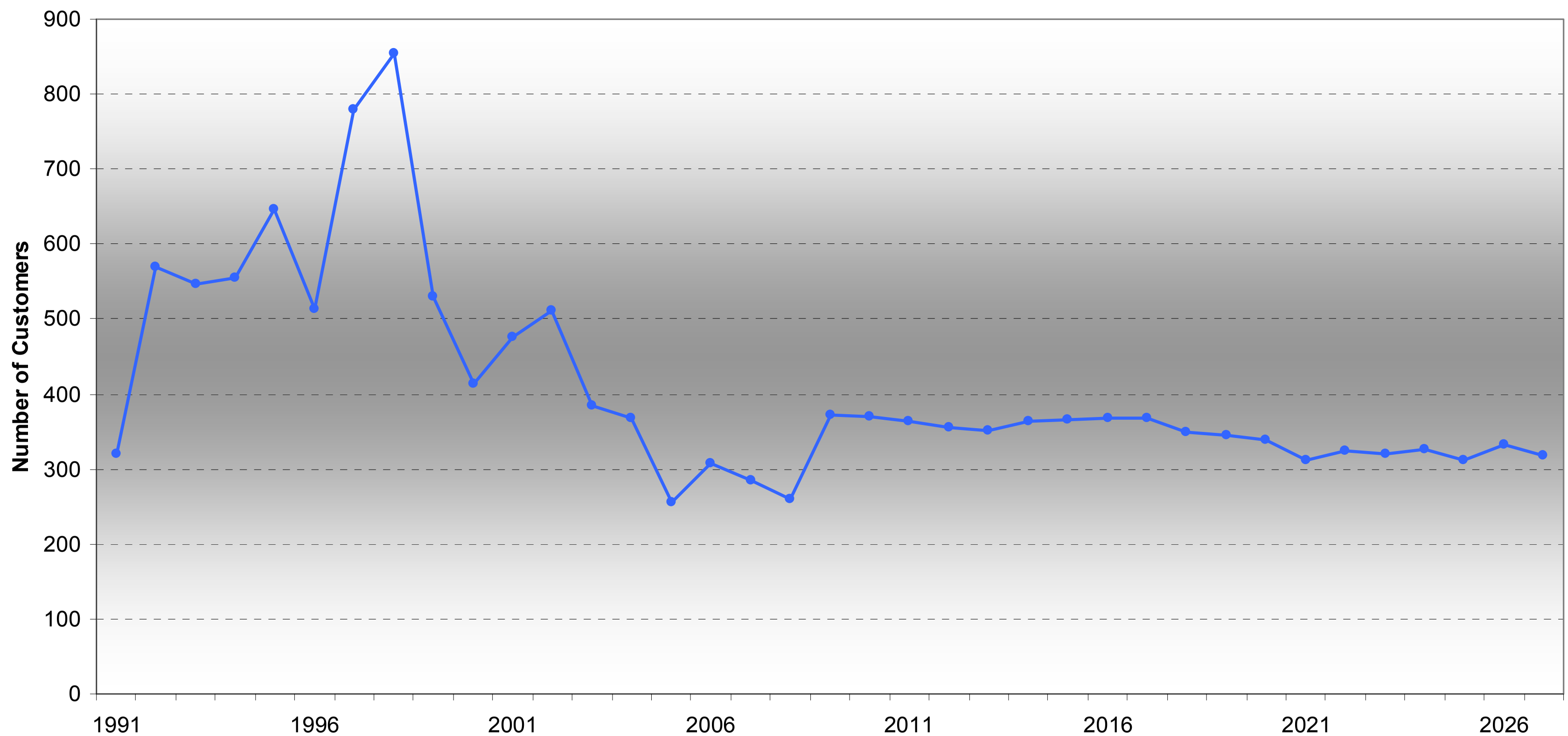


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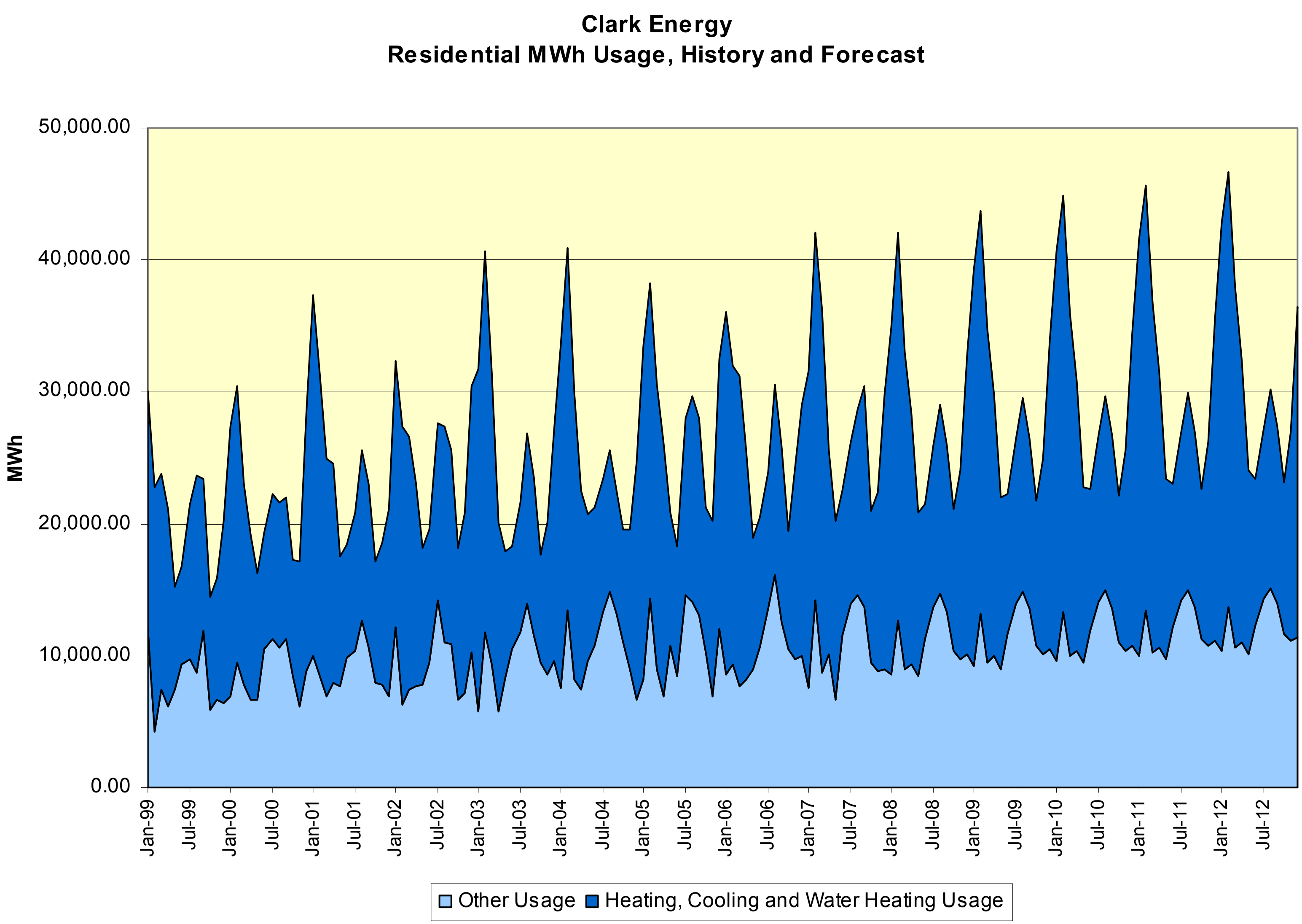
Figure 1-9



Clark Energy
Residential MWh Usage, History and Forecast
MWh
50,000.00
40,000.00
30,000.00
20,000.00
10,000.00
0.00
Jan-99
Jul-99
Jan-00
Jul-00
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08
Jan-09
Jul-09
Jan-10
Jul-10
Jan-11
Jul-11
Jan-12
Jul-12
Other Usage
Heating, Cooling and Water Heating Usage

Methodology and Results *(continued)*

Small Commercial Forecast

Small commercial sales are projected using two equations, a customer equation and a small commercial sales equation. Both are determined through regression analysis and utilize inputs relating to the economy, electric price, and the residential customer forecast. Small commercial projections are reported in Table 1-7.

Table 1-7

Clark Energy Cooperative
2008 Load Forecast
Small Commercial Summary

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	1,027			53			54,943		
1991	1,047	20	1.9	54	1	1.8	57,046	2,103	3.8
1992	1,064	17	1.6	55	0	0.8	58,436	1,390	2.4
1993	1,090	26	2.4	56	1	2.4	61,275	2,839	4.9
1994	1,126	36	3.3	56	-1	-1.1	62,591	1,316	2.1
1995	1,164	38	3.4	57	1	2.4	66,227	3,637	5.8
1996	1,210	46	4.0	58	1	1.2	69,687	3,460	5.2
1997	1,235	25	2.1	58	1	0.9	71,759	2,072	3.0
1998	1,260	25	2.0	62	4	7.2	78,457	6,698	9.3
1999	1,291	31	2.5	60	-2	-3.7	77,390	-1,067	-1.4
2000	1,327	36	2.8	59	-1	-1.8	78,100	710	0.9
2001	1,363	36	2.7	59	0	0.4	80,559	2,459	3.1
2002	1,400	37	2.7	59	0	-0.1	82,632	2,073	2.6
2003	1,414	14	1.0	61	2	3.7	86,523	3,891	4.7
2004	1,466	52	3.7	61	-1	-0.9	88,922	2,399	2.8
2005	1,562	96	6.5	59	-2	-3.1	91,761	2,839	3.2
2006	1,608	46	2.9	54	-5	-8.9	86,096	-5,665	-6.2
2007	1,615	7	0.4	57	3	6.5	91,533	5,437	6.3
2008	1,628	13	0.8	57	0	0.0	92,297	765	0.8
2009	1,661	33	2.0	57	0	0.0	95,115	2,818	3.1
2010	1,693	32	1.9	58	1	1.8	97,459	2,344	2.5
2011	1,724	31	1.8	58	0	0.0	99,534	2,076	2.1
2012	1,750	26	1.5	58	0	0.0	101,213	1,679	1.7
2013	1,774	24	1.4	58	0	0.0	102,694	1,481	1.5
2014	1,796	22	1.2	58	0	0.0	104,068	1,374	1.3
2015	1,819	23	1.3	58	0	0.0	105,438	1,370	1.3
2016	1,840	21	1.2	58	0	0.0	106,744	1,306	1.2
2017	1,861	21	1.1	58	0	0.0	107,981	1,237	1.2
2018	1,880	19	1.0	58	0	0.0	109,135	1,154	1.1
2019	1,895	15	0.8	58	0	0.0	110,001	865	0.8
2020	1,910	15	0.8	58	0	0.0	110,910	909	0.8
2021	1,925	15	0.8	58	0	0.0	111,831	922	0.8
2022	1,942	17	0.9	58	0	0.0	112,830	999	0.9
2023	1,958	16	0.8	58	0	0.0	113,800	970	0.9
2024	1,975	17	0.9	58	0	0.0	114,853	1,052	0.9
2025	1,992	17	0.9	58	0	0.0	115,861	1,008	0.9
2026	2,010	18	0.9	58	0	0.0	116,900	1,040	0.9
2027	2,026	16	0.8	58	0	0.0	117,889	989	0.8

Methodology and Results *(continued)*

Large Commercial Forecast

Large commercial customers are those with loads 1 MW or greater. Clark Energy currently has 3 customers in this class and is projected to increase to 4 customers by 2027. Large commercial results are reported in Table 1-8.

Table 1-8

Clark Energy Cooperative
2008 Load Forecast
Large Commercial Summary

	Customers			Use Per Customer			Class Sales		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	1			716			716		
1991	1	0	0.0	122	-594	-82.9	122	-594	-82.9
1992	1	0	0.0	1,919	1,796	1468.3	1,919	1,796	1468.3
1993	1	0	0.0	1,565	-353	-18.4	1,565	-353	-18.4
1994	1	0	0.0	3,728	2,163	138.2	3,728	2,163	138.2
1995	1	0	0.0	6,625	2,897	77.7	6,625	2,897	77.7
1996	2	1	100.0	4,111	-2,514	-38.0	8,222	1,597	24.1
1997	1	-1	-50.0	5,376	1,265	30.8	5,376	-2,846	-34.6
1998	0	-1	-100.0				1,717	-3,659	-68.1
1999	1	1		2,050			2,050	332	19.3
2000	1	0	0.0	9,212	7,163	349.5	9,212	7,163	349.5
2001	1	0	0.0	10,870	1,658	18.0	10,870	1,658	18.0
2002	1	0	0.0	10,726	-144	-1.3	10,726	-144	-1.3
2003	2	1	100.0	4,182	-6,544	-61.0	8,364	-2,362	-22.0
2004	1	-1	-50.0	8,173	3,991	95.4	8,173	-191	-2.3
2005	1	0	0.0	9,095	922	11.3	9,095	922	11.3
2006	3	2	200.0	5,464	-3,631	-39.9	16,391	7,296	80.2
2007	3	0	0.0	5,159	-305	-5.6	15,477	-915	-5.6
2008	3	0	0.0	4,610	-549	-10.6	13,830	-1,647	-10.6
2009	3	0	0.0	4,671	61	1.3	14,012	183	1.3
2010	3	0	0.0	4,760	89	1.9	14,279	267	1.9
2011	3	0	0.0	4,846	86	1.8	14,537	258	1.8
2012	3	0	0.0	4,916	71	1.5	14,749	212	1.5
2013	3	0	0.0	4,979	63	1.3	14,937	188	1.3
2014	3	0	0.0	5,037	58	1.2	15,111	174	1.2
2015	3	0	0.0	5,095	58	1.1	15,284	174	1.1
2016	3	0	0.0	5,150	55	1.1	15,450	166	1.1
2017	3	0	0.0	5,202	52	1.0	15,607	157	1.0
2018	3	0	0.0	5,251	49	0.9	15,753	146	0.9
2019	3	0	0.0	5,288	37	0.7	15,863	110	0.7
2020	3	0	0.0	5,326	38	0.7	15,978	115	0.7
2021	3	0	0.0	5,365	39	0.7	16,095	117	0.7
2022	3	0	0.0	5,407	42	0.8	16,221	127	0.8
2023	3	0	0.0	5,448	41	0.8	16,344	123	0.8
2024	3	0	0.0	5,493	44	0.8	16,478	133	0.8
2025	3	0	0.0	5,535	43	0.8	16,605	128	0.8
2026	4	1	33.3	6,250	715	12.9	25,001	8,396	50.6
2027	4	0	0.0	6,282	31	0.5	25,127	125	0.5

Methodology and Results *(continued)*

Other Forecast

Clark Energy serves street light accounts which are classified in the ‘Other’ category. This class is modeled separately. Results are reported in Table 1-9.

Table 1-9
Clark Energy Cooperative
2008 Load Forecast
Other Summary

	Customers			Use Per Customer			Class Sales		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	12			3,097			446		
1991	15	3	25.0	2,659	-438	-14.1	479	33	7.3
1992	19	4	26.7	2,313	-346	-13.0	527	49	10.2
1993	42	23	121.1	1,183	-1,130	-48.8	596	69	13.1
1994	59	17	40.5	922	-262	-22.1	653	56	9.4
1995	104	45	76.3	641	-281	-30.5	800	147	22.6
1996	164	60	57.7	510	-131	-20.5	1,003	203	25.4
1997	134	-30	-18.3	575	66	12.9	925	-78	-7.8
1998	18	-116	-86.6	2,799	2,223	386.5	605	-321	-34.6
1999	19	1	5.6	2,558	-241	-8.6	583	-21	-3.5
2000	21	2	10.5	2,145	-413	-16.1	541	-43	-7.3
2001	22	1	4.8	2,022	-123	-5.7	534	-7	-1.2
2002	21	-1	-4.5	2,142	120	5.9	540	6	1.1
2003	21	0	0.0	2,134	-9	-0.4	538	-2	-0.4
2004	23	2	9.5	2,029	-105	-4.9	560	22	4.1
2005	27	4	17.4	1,961	-67	-3.3	636	76	13.5
2006	29	2	7.4	1,866	-96	-4.9	649	14	2.2
2007	31	2	6.9	1,734	-132	-7.1	645	-4	-0.7
2008	31	0	0.0	1,776	42	2.4	661	16	2.4
2009	31	0	0.0	1,769	-7	-0.4	658	-3	-0.4
2010	31	0	0.0	1,766	-2	-0.1	657	-1	-0.1
2011	31	0	0.0	1,767	1	0.0	657	0	0.0
2012	31	0	0.0	1,770	3	0.2	658	1	0.2
2013	31	0	0.0	1,774	4	0.2	660	2	0.2
2014	31	0	0.0	1,780	5	0.3	662	2	0.3
2015	31	0	0.0	1,785	6	0.3	664	2	0.3
2016	31	0	0.0	1,792	6	0.4	667	2	0.4
2017	31	0	0.0	1,798	7	0.4	669	2	0.4
2018	31	0	0.0	1,805	7	0.4	671	2	0.4
2019	31	0	0.0	1,812	7	0.4	674	3	0.4
2020	31	0	0.0	1,818	7	0.4	676	2	0.4
2021	31	0	0.0	1,825	7	0.4	679	2	0.4
2022	31	0	0.0	1,832	6	0.4	681	2	0.4
2023	31	0	0.0	1,838	6	0.4	684	2	0.4
2024	31	0	0.0	1,844	6	0.3	686	2	0.3
2025	31	0	0.0	1,851	6	0.3	688	2	0.3
2026	31	0	0.0	1,857	6	0.3	691	2	0.3
2027	31	0	0.0	1,863	6	0.3	693	2	0.3

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Methodology and Results *(continued)*

Peak Day Weather Scenarios

Extreme temperatures can dramatically influence Clark Energy's peak demands. Table 1-10 and Figure 1-10 reports the impact of extreme weather on system demands.

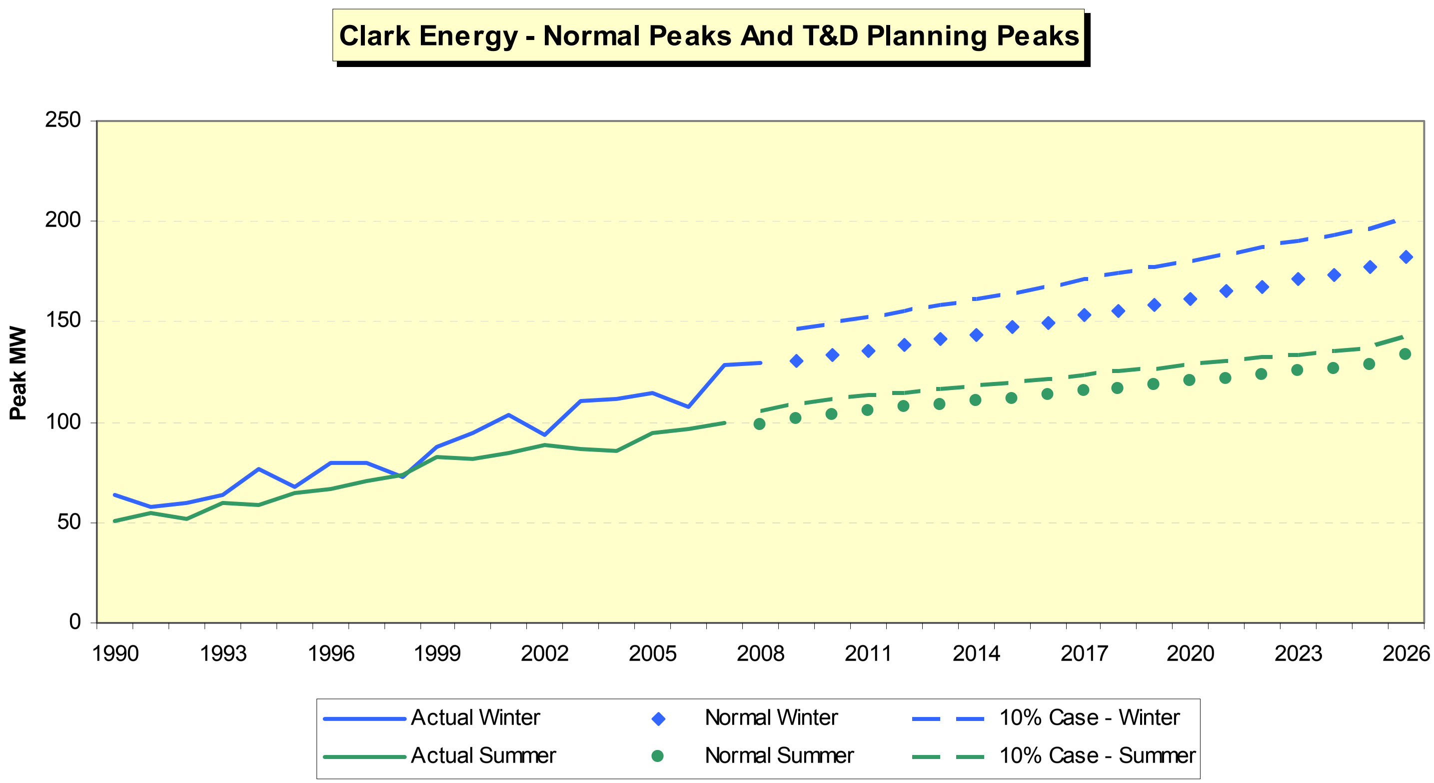
Table 1-10

Clark Energy
Peak Day Weather Scenarios

Winter Peak Day Minimum Temperatures					
	Mild	Normal		**Extreme**	
Degrees	10	-3	-12	-17	-25
Probability	*99%*	*50%*	*20%*	*10%*	*3%*
Occurs Once Every		**2 Years**	**5 Years**	**10 Years**	**30 Years**
Noncoincident Winter Peak Demand - MW					
Season	Mild	Normal		Extreme	
2008 - 09	115	130	140	146	155
2009 - 10	118	133	144	150	159
2010 - 11	120	136	146	152	162
2011 - 12	123	139	149	155	165
2012 - 13	126	141	152	158	168
2013 - 14	128	144	155	161	171
2014 - 15	131	147	158	164	174
2015- 16	133	150	161	167	178
2016 - 17	136	153	165	171	181
2017 - 18	139	156	167	174	184
2018 - 19	142	159	171	177	188
2019-20	144	162	174	180	191
2020-21	147	165	177	184	194
2021-22	150	168	180	187	198
2022-23	153	171	183	190	201
2023-24	155	173	186	193	204
2024-25	159	177	190	197	208
2025-26	164	182	195	202	214
2026-27	167	185	198	206	217

Summer Peak Day Maximum Temperatures				
	Normal		**Extreme**	
Degrees	96	98	100	104
Probability	*50%*	*20%*	*10%*	*3%*
	2 Years	**5 Years**	**10 Years**	**30 Years**
Noncoincident Summer Peak Demand - MW				
Year	Normal		Extreme	
2008	99	102	106	113
2009	102	106	109	117
2010	104	108	111	119
2011	106	109	113	121
2012	107	111	115	122
2013	109	113	117	124
2014	110	114	118	126
2015	112	116	120	128
2016	114	117	122	130
2017	115	119	124	132
2018	117	121	125	133
2019	119	123	127	135
2020	120	124	128	137
2021	122	126	130	139
2022	124	128	132	141
2023	125	129	134	143
2024	127	131	135	144
2025	129	133	137	146
2026	133	137	142	151
2027	135	139	144	153

Figure 1-10


Clark Energy - Normal Peaks And T&D Planning Peaks
Peak MW
250
200
150
100
50
0
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
2026
Actual Winter
Actual Summer
Normal Winter
Normal Summer
10% Case - Winter
10% Case - Summer

Appendix B
Stone Rd. Substation

The Stone Rd. Substation was proposed in Load Level 1 at the intersection of the existing EKPC 69-kV transmission line and Sideview Feeder 2 as an alternative to the substation transformer upgrade at Sideview Substation and an extensive multi-phase project for Sideview Feeder 2 included in the Base Case in the 2010 Long Range Plan.

The new substation includes (1) three-phase, 69-25 kV, 5 MVA transformer and (2) feeder reclosers. The proposed improvements for the new substation were compared to the cost of the Base Case system improvements to serve the projected load. Clark Energy has received approval from EKPC for the Stone Rd Substation. The cost of proposed improvements for this the Stone Rd. Substation are shown in Table B-1.

Table B-1
Stone Rd. Substation
Capital Improvements Summary (2009 $'s)

Load Level	Description	Estimated Cost
Transmission Improvements		
1	69kV Tap Structure and Two-Way Air-Break Switch	$80,000
	SUBTOTAL TRANSMISSION	$80,000
Substation Improvements		
1	*New* **Stone Rd** - Construct a new substation with (1) 3-ph, 69-24.9kV, 5 MVA transformer and (2) feeder reclosers to relieve transformer loading on Sideview Substation, 1ph loading, feeder voltage, and improve reliability for the area served	$726,200
20	**Blevins Valley** - Relocate the existing (1) 3-ph, 69-12.5 kV, 11.2/14 MVA transformer from Clay City to Blevins Valley to replace the existing (3) 1-ph, 69-7.2 kV, 1.67 MVA transformers for additional capacity	$150,000
18	**Clay City** - Replace the existing (1) 3-ph, 69-12.5 kV, 11.2/14 MVA transformer with (1) 3-ph, 69 12.5 kV, 15/20 MVA transformer for additional capacity	$900,000
1	**Clay City** - Add recloser and buswork at the substation for new feede	$50,000
15	**Hope** - Replace high-side fuse to utilize the rated capacity of transforme	$2,600
8	**Hunt** - Replace high-side fuse to utilize the rated capacity of transforme	$2,600
20	**Hunt** - Replace the existing (1) 3-ph, 69-24.9 kV, 11.2 MVA transformer with (1) 3-ph, 69-24.9 kV, 15/20/25 MVA transformer for additional capacity	$932,000
7	**Mariba** - Replace the existing (3) 1-ph, 69-7.2 kV, 1.67 MVA transformers with (1) 3-ph, 69-12.5 kV, 11.2/14 MVA transformer for additional capacity	$400,000
6	**Mariba** - Replace the existing substation regulators	$54,000
1	**Mariba** - Replace the existing (3) 1-ph, 1.0 MVA autos at ST.8 with (3) 1-ph, 2.5 MVA autos for additional capacity on Feeder 2	$285,660
15	**Mt. Sterling** - Replace the existing (3) 1-ph, 1.67 MVA autos at ST.5 with (1) 3-ph, 2.5 MVA autos for additional capacity on Feeder 2	$285,660
13	**Reid Village** - Replace the existing substation regulators for additional capacity	$160,000
17	**Reid Village** - replace the existing (3) 1-ph, 69-7.2 kV, 1.67 MVA transformers for additional capacity with (1) 3-ph, 69-12.5 kV, 11.2/14 MVA transformer	$400,000
16	~~**Sideview** - Replace the existing (1) 3-ph, 69-12.5 kV, 11.2/14 MVA transformer with (1) 3-ph, 69 12.5 kV, 15/20/25 MVA transformer for additional capacity~~	$0
9	**Sideview** - Replace the existing 5.6 MVA autotransformer at ST.29 with a 3-ph 10 MVA autc	$368,000
10	**Union City** - Replace the existing (1) 3-ph, 69-24.9 kV, 12 MVA transformer with (1) 3-ph, 69 24.9 kV, 15/20/25 MVA transformer for additional capacity	$932,000
	SUBTOTAL SUBSTATION	$5,648,720
Distribution Improvements		
1	CWP Distribution Improvements - LL1	$1,423,500
2	CWP Distribution Improvements - LL2	249,400
3	CWP Distribution Improvements - LL3	124,500
4	CWP Distribution Improvements - LL4	11,000
5	LRP Distribution Improvements - LL5	757,500
6	LRP Distribution Improvements - LL6	381,750
7	LRP Distribution Improvements - LL7	3,739
8	LRP Distribution Improvements - LL8	36,900
9	LRP Distribution Improvements - LL9	916,760
10	LRP Distribution Improvements - LL10	411,383
11	LRP Distribution Improvements - LL11	554,300
12	LRP Distribution Improvements - LL12	433,013
13	LRP Distribution Improvements - LL13	553,236
14	LRP Distribution Improvements - LL14	485,300
15	LRP Distribution Improvements - LL15	74,300
16	LRP Distribution Improvements - LL16	0
17	LRP Distribution Improvements - LL17	0

Table B-1
Stone Rd. Substation
Capital Improvements Summary (2009 $'s)

Load Level	Description	Estimated Cost
18	LRP Distribution Improvements - LL18	0
19	LRP Distribution Improvements - LL19	61,900
20	LRP Distribution Improvements - LL20	$0
	SUBTOTAL DISTRIBUTION	$6,478,479
TOTAL CAPITAL COST		$12,207,199
Losses Summary		
0	Calculated Distribution Losses (kW)	1,579
20	Calculated Distribution Losses (kW)	4,176
Present Worth Cost		
20	20-Year Cumulative Present Worth Cost	$12,528,334

Table B-2
Stone Rd. Substation
Present Worth Calculations

	Load Level																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
TRANSMISSION																				
New Investment	$80,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Inflated Investment	$80,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Cost	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000	$80,000
Annual Depreciation	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Cumulative Depreciation	$2,000	$4,000	$6,000	$8,000	$10,000	$12,000	$14,000	$16,000	$18,000	$20,000	$22,000	$24,000	$26,000	$28,000	$30,000	$32,000	$34,000	$36,000	$38,000	$40,000
Investment Book Value	$78,000	$76,000	$74,000	$72,000	$70,000	$68,000	$66,000	$64,000	$62,000	$60,000	$58,000	$56,000	$54,000	$52,000	$50,000	$48,000	$46,000	$44,000	$42,000	$40,000
Capital Recovery	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662
Operations and Maintenance	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
Taxes	$31	$30	$30	$29	$28	$27	$26	$26	$25	$24	$23	$22	$22	$21	$20	$19	$18	$18	$17	$16
Other Operating Expenses	$39	$38	$37	$36	$35	$34	$33	$32	$31	$30	$29	$28	$27	$26	$25	$24	$23	$22	$21	$20
Total Operating Expense	$2,470	$2,468	$2,467	$2,465	$2,463	$2,461	$2,459	$2,458	$2,456	$2,454	$2,452	$2,450	$2,449	$2,447	$2,445	$2,443	$2,441	$2,440	$2,438	$2,436
SUBSTATION																				
New Investment	$1,061,860	$0	$0	$0	$0	$54,000	$400,000	$2,600	$368,000	$932,000	$0	$0	$160,000	$0	$288,260	$0	$400,000	$900,000	$0	$1,082,000
Inflated Investment	$1,061,860	$0	$0	$0	$0	$64,135	$491,702	$3,308	$484,586	$1,270,220	$0	$0	$241,771	$0	$466,605	$0	$693,594	$1,615,208	$0	$2,080,146
Cumulative Cost	$1,061,860	$1,061,860	$1,061,860	$1,061,860	$1,061,860	$1,125,995	$1,617,697	$1,621,005	$2,105,591	$3,375,811	$3,375,811	$3,375,811	$3,617,582	$3,617,582	$4,084,187	$4,084,187	$4,777,781	$6,392,989	$6,392,989	$8,473,136
Annual Depreciation	$21,237	$21,237	$21,237	$21,237	$21,237	$22,520	$32,354	$32,420	$42,112	$67,516	$67,516	$67,516	$72,352	$72,352	$81,684	$81,684	$95,556	$127,860	$127,860	$169,463
Cumulative Depreciation	$21,237	$42,474	$63,712	$84,949	$106,186	$128,706	$161,060	$193,480	$235,592	$303,108	$370,624	$438,140	$510,492	$582,844	$664,527	$746,211	$841,767	$969,627	$1,097,486	$1,266,949
Investment Book Value	$1,040,623	$1,019,386	$998,148	$976,911	$955,674	$997,289	$1,456,637	$1,427,525	$1,869,999	$3,072,703	$3,005,187	$2,937,671	$3,107,090	$3,034,738	$3,419,660	$3,337,976	$3,936,015	$5,423,363	$5,295,503	$7,206,187
Capital Recovery	$58,165	$58,165	$58,165	$58,165	$58,165	$61,678	$88,612	$88,793	$115,337	$184,916	$184,916	$184,916	$198,159	$198,159	$223,718	$223,718	$261,711	$350,187	$350,187	$464,131
Operations and Maintenance	$21,237	$21,237	$21,237	$21,237	$21,237	$22,520	$32,354	$32,420	$42,112	$67,516	$67,516	$67,516	$72,352	$72,352	$81,684	$81,684	$95,556	$127,860	$127,860	$169,463
Taxes	$416	$408	$399	$391	$382	$399	$583	$571	$748	$1,229	$1,202	$1,175	$1,243	$1,214	$1,368	$1,335	$1,574	$2,169	$2,118	$2,882
Other Operating Expenses	$520	$510	$499	$488	$478	$499	$728	$714	$935	$1,536	$1,503	$1,469	$1,554	$1,517	$1,710	$1,669	$1,968	$2,712	$2,648	$3,603
Total Operating Expense	$22,174	$22,155	$22,136	$22,116	$22,097	$23,417	$33,665	$33,705	$43,795	$70,282	$70,221	$70,160	$75,148	$75,083	$84,761	$84,688	$99,098	$132,741	$132,626	$175,948
DISTRIBUTION																				
New Investment	$1,423,500	$249,400	$124,500	$11,000	$757,500	$381,750	$3,739	$36,900	$916,760	$411,383	$554,300	$433,013	$553,236	$485,300	$74,300	$0	$0	$0	$61,900	$0
Inflated Investment	$1,423,500	$258,129	$133,368	$12,196	$869,249	$453,399	$4,596	$46,947	$1,207,198	$560,672	$781,895	$632,185	$835,977	$758,988	$120,269	$0	$0	$0	$114,979	$0
Cumulative Cost	$1,423,500	$1,681,629	$1,814,997	$1,827,192	$2,696,441	$3,149,840	$3,154,436	$3,201,383	$4,408,581	$4,969,253	$5,751,148	$6,383,333	$7,219,311	$7,978,298	$8,098,567	$8,098,567	$8,098,567	$8,098,567	$8,213,546	$8,213,546
Annual Depreciation	$43,136	$50,958	$55,000	$55,369	$81,710	$95,450	$95,589	$97,012	$133,593	$150,583	$174,277	$193,434	$218,767	$241,767	$245,411	$245,411	$245,411	$245,411	$248,895	$248,895
Cumulative Depreciation	$43,136	$94,095	$149,095	$204,464	$286,175	$381,624	$477,213	$574,225	$707,818	$858,402	$1,032,679	$1,226,113	$1,444,880	$1,686,647	$1,932,058	$2,177,469	$2,422,880	$2,668,291	$2,917,187	$3,166,082
Investment Book Value	$1,380,364	$1,587,534	$1,665,902	$1,622,728	$2,410,267	$2,768,216	$2,677,223	$2,627,158	$3,700,763	$4,110,852	$4,718,469	$5,157,220	$5,774,430	$6,291,652	$6,166,510	$5,921,098	$5,675,687	$5,430,276	$5,296,359	$5,047,464
Capital Recovery	$88,955	$105,085	$113,419	$114,181	$168,501	$196,834	$197,121	$200,055	$275,492	$310,529	$359,389	$398,895	$451,135	$498,564	$506,080	$506,080	$506,080	$506,080	$513,265	$513,265
Operations and Maintenance	$58,364	$68,947	$74,415	$74,915	$110,554	$129,143	$129,332	$131,257	$180,752	$203,739	$235,797	$261,717	$295,992	$327,110	$332,041	$332,041	$332,041	$332,041	$336,755	$336,755
Taxes	$552	$635	$666	$649	$964	$1,107	$1,071	$1,051	$1,480	$1,644	$1,887	$2,063	$2,310	$2,517	$2,467	$2,368	$2,270	$2,172	$2,119	$2,019
Other Operating Expenses	$690	$794	$833	$811	$1,205	$1,384	$1,339	$1,314	$1,850	$2,055	$2,359	$2,579	$2,887	$3,146	$3,083	$2,961	$2,838	$2,715	$2,648	$2,524
Total Operating Expense	$59,606	$70,376	$75,914	$76,375	$112,723	$131,635	$131,741	$133,621	$184,083	$207,439	$240,044	$266,358	$301,189	$332,773	$337,591	$337,370	$337,149	$336,929	$341,522	$341,298
LOSSES ($)																				
Distribution Cu	$214,239	$224,914	$236,122	$247,888	$260,240	$273,207	$286,821	$301,114	$316,118	$331,870	$348,407	$365,768	$383,995	$403,129	$423,217	$444,306	$466,445	$489,688	$514,089	$539,706
TOTALS																				
Capital Recovery	$151,782	$167,913	$176,247	$177,009	$231,328	$263,174	$290,395	$293,510	$395,492	$500,107	$548,968	$588,473	$653,957	$701,386	$734,461	$734,461	$772,453	$860,929	$868,114	$982,058
Operating Expenses	$84,250	$94,999	$100,516	$100,957	$137,284	$157,514	$167,866	$169,784	$230,333	$280,175	$312,717	$338,969	$378,785	$410,302	$424,798	$424,501	$438,689	$472,109	$476,586	$519,682
Losses	$214,239	$224,914	$236,122	$247,888	$260,240	$273,207	$286,821	$301,114	$316,118	$331,870	$348,407	$365,768	$383,995	$403,129	$423,217	$444,306	$466,445	$489,688	$514,089	$539,706
TOTAL ANNUAL COST	$450,271	$487,825	$512,885	$525,853	$628,852	$693,895	$745,082	$764,407	$941,943	$1,112,152	$1,210,092	$1,293,210	$1,416,736	$1,514,817	$1,582,475	$1,603,267	$1,677,587	$1,822,726	$1,858,789	$2,041,446
Annual Present Worth Cost	$428,829	$442,472	$443,049	$432,621	$492,722	$517,795	$529,516	$517,381	$607,185	$682,765	$707,516	$720,108	$751,326	$765,086	$761,197	$734,475	$731,926	$757,380	$735,586	$769,400
Cumulative Annual Present Worth Cost	$428,829	$871,301	$1,314,350	$1,746,971	$2,239,692	$2,757,488	$3,287,004	$3,804,385	$4,411,570	$5,094,335	$5,801,850	$6,521,958	$7,273,284	$8,038,369	$8,799,567	$9,534,042	$10,265,968	$11,023,348	$11,758,934	$12,528,334

Table B-3
Stone Rd. Substation
Distribution Cost

RUS CODE	Model Line Sections	General Description	Load Level	Miles	2009 $
		Blevins Valley			
		Remove reloser	**9**		$1,000
	PL.25719 to PL.11058	Reconductor and multi-phase with 3-ph 1/0 ACSR	**9**	0.51	$51,000
		Replace switch with a 25V4E	**9**		$5,500
		Replace switch with a 50V4E	**9**		$5,500
		Replace switch with a 70V4E	**9**		$5,500
		Replace recloser with a 70V4E	**9**		$5,500
		Replace three-phase hydraulic recloser with VXE	**8**		$30,400
		Clay City			
378	PL.10953 to PL.48919	New construction Three-phase 336 Hendrix	**1**	0.34	$56,100
378	PL.48921 to PL.48919	Reconductor and Multi-phase 336 ACSR	**1**	0.61	$76,250
378	PL.11553 to PL.52348	Reconductor to Three-phase 336 ACSR	**1**	0.05	$6,250
372	PL.15497 to PL.11743	Multi-phase to three-phase 1/0 ACSR	**1**	1.53	$153,000
604-07		Remove regulator	**1**		$2,800
379	PL.52126 to PL.12959	Reconductor and Multi-phase 336 ACSR	**3**	0.98	$122,500
603-01		Replace a switch and remove a recloser	**1**		$7,000
603-02		Add (2) single-phase 70V4E reclosers	**1**		$11,000
603-03		Relocate recloser	**3**		$2,000
		New Construction single-phase 2 ACSR	**7**	0.07	$3,739
		Frenchburg			
380	PL.29091 to PL.19753 and PL.19206 to PL.53851	Reconductor to three-phase 336 ACSR	**1**	1.38	$172,500
604-01		Relocate regulator	**1**		$4,400
604-02		Relocate regulator	**1**		$4,400
	PL.37743 to PL.40892	Reconductor to three-phase 336 ACSR	**9**	2.99	$373,750
		Remove (2) regulators	**9**		$5,600
601-1		Replace ST.27 w/ (1) 1ph 333kVA	**1**		$2,500
		Hardwicks Creek			
373	PL.53477 to PL.12797	Multi-phase to three-phase 1/0 ACSR	**1**	1.61	$161,000
603-04		Replace recloser with a 70V4E. Relocate recloser. Add (2) 70V4E reclosers	**1**		$19,500
		High Rock			
604-04		Install (1) single-phase 100 A regulator	**1**		$10,000
		Hinkston			
		Remove recloser and replace with VWVE#1	**12**		$31,400
		Hope			
	PL.47204 to PL.98	Reconductor and multi-phase with three phase 1/0 ACSR	**19**	0.24	$24,000
		Relocate recloser. Replace fuse with 70V4E recloser. Replace recloser with three phase VWVE#1	**19**		$37,900
		Hunt			
374	PL.27792 to PL.16349	Reconductor and multi-phase to three-phase 1/0 ACSR	**1**	1.14	$114,000
375	PL.20386 to PL.9336	Reconductor and multi-phase to three-phase 1/0 ACSR	**2**	0.66	$66,000
603-05		Replace recloser with (3) 50V4E reclosers	**1**		$11,300
603-06		Add (2) 50V4E reclosers	**2**		$11,000

Table B-3
Stone Rd. Substation
Distribution Cost

RUS CODE	Model Line Sections	General Description	Load Level	Miles	2009 $
	PL.16002 to PL.16109	Multi-phase and reconductor with three-phase 1/0 ACSR	**14**	4.35	$435,000
		Replace fuse with three-phase VWVE#1. Install (1) 50V4E	**14**		$15,800
		Replace device with a 70V4E recloser	**9**		$11,300
	PL.8055 to PL.16538	Reconductor to single-phase 2 ACSR	**9**	3.03	$60,542
		Jeffersonville			
		Remove (2) 333 kVA step transformers at ST.10 and relocate	**12**		$10,000
	PL.17884 to PL.6226	Single-phase conversion from 7.2 kV to 14.4 kV	**12**	10.12	$91,108
	Pl.18299 to PL.15416	Multi Phase to 336 ACSR	**6**	1.79	$223,750
		Mt. Sterling			
381	PL.16469 to PL.10631	Reconductor and multi-phase to three-phase 336 ACSR	**2**	1.08	$135,000
	PL.6762 to PL.7540	Reconductor to three-phase 336 ACSR	**5**	4.36	$545,000
603-08		Replace recloser with three-phase VWVE#1 and relocate (3) 50L's. Remove recloser	**2**		$37,400
	PL.17759 to PL.14233	Reconductor and multi-phase to 1/0 ACSR	**11**	2.65	$265,000
		Replace reloser with (3) 70V4E	**11**		$10,300
		Reid Village			
382	PL.29149 to PL.7556	Reconductor to three-phase 336 ACSR	**1**	0.66	$82,500
		Reconductor and multi-phase to 336 ACSR	**12**	2.27	$283,750
		Replace recloser with (3) 70V4E	**12**		$11,300
		New construction of 4 ACSR	**12**	0.11	$5,455
	PL.46461 to PL.10740	Reconductor and multi-phase to 1/0 ACSR	**15**	0.63	$63,000
		Replace recloser with (3) 50V4E	**15**		$11,300
604-05		Install (3) single-phase 100A regulators	**1**		$30,000
		Sideview			
384	PL.12440 to PL.11650	~~Reconductor and multi-phase to three-phase 1/0 ACSR~~	**1**	6.36	
603-09		~~Remove reclosers. Replace switch with (3) 70V4E~~	**1**		
	PL.39712 to PL.50016	Recondcutro and multi-phase with three-phase 1/0ACSR	**10**	2.10	$210,000
		Add (2) 50E reclosers	**10**		$11,000
	PL.42855 to PL.11601	Reconductor and multi-phase to three-phase 1/0 ACSR	**14**	0.28	$28,000
		Remove recloser. Add (1) 35V4E	**14**		$6,500
	PL.38766 to PL.10393	Reconductor to three-phase 336 ACSR	**13**	3.56	$445,000

Table B-3
Stone Rd. Substation
Distribution Cost

RUS CODE	Model Line Sections	General Description	Load Level	Miles	2009 $
		Stanton			
	PL.49035 to PL.27422 and PL.51773 to PL.49036	Reconductor to three-phase 336 ACSR	**5**	1.70	$212,500
603-15		Add (2) single-phase 70V4E reclosers	**4**		$11,000
	PL.17519 to PL.13915	Reconductor and multi-phase to 336 ACSR	**9**	1.53	$191,250
		Add (2) 70V4E. Relocate recloser	**9**		$13,000
		New construction of 4 ACSR	**9**	0.04	$1,818
		Replace recloser with 50V4E	**8**		$6,500
		Three Forks			
	PL.14830 to PL.55738	Recondcutor and multi-phase with three-phase 1/0 ACSR	**6**	1.07	$107,000
		Remove recloser	**6**		$1,000
		Trapp			
		Voltage Conversion 7.2 kV to 14.4 kV move load to Miller hunt	**10**	2.07	$18,649
		Replace switch with (1) 70V4L	**10**		$5,500
	PL.15974 to PL.16478	Reconductor and multi-phase to three-phase 336 ASCR	**9**	1.46	$182,500
		Remove recloser and relocate (1) 50V4E	**9**		$3,000
		Voltage Conversion 7.2 kV to 14.4 kV move load to Miller hunt	**13**	5.14	$46,236
		Relocate (3) 35V4E	**13**		$6,000
	PL.41696 to PL.5110	Reconductor and multi-phase to three-phase 1/0 ASCR	**13**	0.56	$56,000
		Treehaven			
	PL.305 to PL.19356	Multi-phase to three-phase #2 ACSR	**10**	0.31	$28,706
	Pl.19356 to PL.29446	300ft of underground 1/0EPR	**10**	0.06	$10,227
	PL.37593 to PL.8899	Reconductor and multi-phase to 1/0 ACSR	**10**	1.17	$117,000
		Union City			
	Pl.37593 to Pl.8899	Remove recloser and replace with 70V4E	**10**		$10,300
	PL.27520 to PL.17560	Multi-phase 1/0 ACSR	**6**	0.50	$50,000
		Van Meter			
383	Pl.9238 to Pl.19628	Reconductor to three-phase 336 ACSR	**1**	2.48	$310,000
		Add 2 50L reclosers	**11**		$11,000
604-03		Install (3) single-phase 219 A	**1**		$46,600
	PL.10042 to PL.8664	Reconductor and multi-phase to three-phase 1/0 ACSR	**11**	2.68	$268,000
		Stone RD			
377	PL.11650 to PL.11645	Three phase 1/0 ACSR	**1**	1.21	$121,000
604-06		Remove (2) regulators	**1**		$5,600
401		(1) single-phase recloser (1) three-phase recloser	**1**		$15,800

Appendix C
Circuit Diagrams

Clark Energy
Construction Work Plan
2010 - 2014
January 2010
Legend
Regulator
Recloser
Switch
New Feeder
Reconductor
Multi-Phase
Reconductor & Multi-Phase
Load Transfer
Phase Balance
Proposed Substation
Existing Substation
Distribution Conductor
LL-01 - 2010-2011
LL-02 - 2011-2012
LL-03 - 2012-2013
LL-04 - 2013-2014
Section Name
Miles From Source
Peaking Season
Voltage Before
Voltage After
Miles
0 0.5 1 2 3 4
N
S
E
W
Stone Rd
SIDEVIEW
VAN METER
TREEHAVEN
HINKSTON
REID VILLAGE
MT. STERLING
MILLER HUNT
CAVE RUN
BLEVINS VALLEY
GRAYSON METER PT
HOPE
FRENCHBURG
JEFFERSONVILLE
MARIBA
HUNT
TRAPP
CLAY CITY
STANTON
BOWEN
HARDWICKS CREEK
HIGH ROCK
THREE FORKS
UNION CITY