OWEN Electric

A Touchstone Energy Cooperative

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Rate Case No. 2008-00154

DATA REQUEST FOR COMMISSION STAFF
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December 29, 2009

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PUBLIC SERVICE COMMISSION

Mr. Jeff Derouen, Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

RE: **PSC Case No. 2008-00154**

Dear Mr. Derouen:

Please find enclosed for filing with the Commission Owen Electric Cooperative's PSC Energy Innovation Update in the above-captioned case, the original and ten (10) copies.

Respectfully yours,

CRAWFORD & BAXTER, P.S.C.

James M. Crawford
Counsel for Owen Electric Cooperative, Inc.

JMC/mns

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF OWEN ELECTRIC COOPERATIVE, INC., FOR ADJUSTMENT OF RATES))) CASE NO. 2008-00154

NOTICE OF FILING

*** *** *** *** ***

Pursuant to the Kentucky Public Service Commission's Order entered June 25, 2009, comes now the Applicant Owen Electric Cooperative, Inc., by counsel, and files with the Commission its detailed report addressing its future plans for energy efficiency and demand, attached hereto as Exhibit "1".

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Attorney for Applicant
Owen Electric Cooperative, Inc.

BY: ______________________
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CERTIFICATE OF SERVICE

This is to certify that a true and correct copy of the foregoing Notice of Filing was mailed postage pre-paid on this the 29th day of December, 2009, to:

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Hon. Quang Nguyen
Kentucky Public Service Commission
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Hon. Paul Adams
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF OWEN ELECTRIC COOPERATIVE, INC. FOR ADJUSTMENT OF RATES	)))	CASE NO. 2008-00154

ORDER

On August 27, 2008, Owen Electric Cooperative Inc. ("Owen") filed an application requesting approval to increase its electric rates and to make changes to certain nonrecurring charges. Owen proposes to adjust its electric rates to increase its operating revenues from $125,997,488 to $130,061,883, an increase of $4,064,395.[1] Owen's application provided for the new rates to become effective for services rendered on or after September 27, 2008. By this Order, the Commission approves the proposed nonrecurring charges and establishes electric rates that will produce annual revenues of $129,832,928, an increase of $3,835,440 over normalized revenues of $125,997,488.

Owen is a consumer-owned rural electric cooperative organized pursuant to KRS Chapter 279 and engaged in the sale of electric energy to approximately 56,794 customers in the Kentucky counties of Boone, Campbell, Carroll, Gallatin, Kenton,

[1] Owen's application did not incorporate the pass-through increase from East Kentucky Power Cooperative, Inc. ("EKPC"). Therefore, these amounts do not include the $6,462,157 pass-though amount authorized by the Commission on March 31, 2009 in Case No. 2008-00409. Operating revenues of $125,997,488 exclude Fuel Adjustment Clause revenues, environmental surcharge revenues, and other electric revenues.

Owen, Pendleton, and Scott.[2] It is one of sixteen member distribution cooperatives that own and receive wholesale power from EKPC.

Pursuant to an Order dated September 15, 2008, the Commission suspended Owen's proposed rates for a period of five months, from September 27, 2008 up to and including February 26, 2009, in order to investigate the reasonableness of Owen's application. The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"), and Gallatin Steel Company were granted full intervention in this proceeding.

Following extensive discovery, the Commission held a public hearing on the proposed rate adjustment on March 25, 2009. The following persons pre-filed Direct Testimony and testified at the hearing on behalf of Owen: Mark Stallons, President and Chief Executive Officer ("CEO"); Rebecca Witt, Senior Vice President for Corporate Services and the Chief Financial Officer; Alan M. Zumstein, Certified Public Accountant; and James R. Adkins, Consultant.[3]

TEST PERIOD

Owen proposes to use the 12-month period ending December 31, 2007 as the test period to determine the reasonableness of its proposed rates. The Commission

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[2] Annual Report of Owen to the Public Service Commission of the Commonwealth of Kentucky for the Calendar Year Ended December 31, 2008 at 13 and 19.

[3] Robert A. Hood filed Direct Testimony with the application because he was Owen's President and CEO when the application was filed. On January 5, 2009, Mr. Hood retired and was replaced by Mr. Stallons. On January 27, 2009, Owen submitted the Direct Testimony of Mr. Stallons.

finds the use of this test period to be reasonable. In using an historic test period, the Commission gives full consideration to appropriate known and measurable changes.

VALUATION

Rate Base

Owen proposed a net investment rate base of $129,193,682[4] based on the test-year-end value of plant in service, the 13-month average balances for materials and supplies and prepayments, the cash working capital allowance, minus the adjusted accumulated depreciation and the test-year-end level of customer advances for construction. Neither intervenor stated a position on Owen's rate base.

The Commission concurs with Owen's proposed rate base with the exception that working capital has been adjusted to reflect the pro forma adjustments to operation and maintenance expenses found reasonable herein. Based on this adjustment, Owen's net investment rate base for rate-making purposes is as follows:

Utility Plant in Service	$ 187,716,197
ADD:	
Materials and Supplies	$ 1,141,357
Prepayments	483,537
Working Capital	1,780,333
Subtotal	$ 191,121,424
DEDUCT:	
Accumulated Depreciation	$ 61,301,494
Customer Advances for Construction	637,286
Subtotal	$ 61,938,780
NET INVESTMENT RATE BASE	$ 129,182,644

[4] Application, Exhibit K, page 1 of 7.

Capitalization and Capital Structure

The Commission finds that Owen's capitalization at test-year-end for rate-making purposes was $124,461,923[5] and consisted of $40,870,668 in equity[6] and $83,591,255 in long-term debt. Using this capital structure, Owen's equity to total capitalization ratio is 32.84 percent.

REVENUES AND EXPENSES

Owen proposed several adjustments to revenues and expenses to reflect current and expected operating conditions. Those adjustments are contained in Table 1 below.

Table 1: Owen's Proposed Adjustments		
Descriptions		Adjustments
Payroll – Salaries	$	156,846
Payroll Taxes	$	230
Normalize Depreciation	$	(1,175,664)
Normalize Property Taxes	$	108,157
Normalize Interest Exp. Long-Term Debt	$	478,648
Financial Accounting Standards 106 Costs	$	40,590
Donations	$	(68,267)
Professional Services	$	(853)
Directors Fees	$	(154,035)
Miscellaneous Expense	$	6,279
Normalize Nonrecurring revenues	$	235,087
Rate Case Amortization	$	24,000
Normalize Expenses	$	(15,151,053)
Normalize Revenues	$	(15,219,861)

The Commission finds that these 14 adjustments proposed by Owen and not opposed by the intervenors are reasonable and should be accepted.

[5] Id.

[6] The Commission normally excludes generation and transmission capital credits ("GTCCs") from equity and the capital structure. During the test year, Owen had no GTCCs.

In reviewing Owen's responses to the information requests, the AG identified several items included in Owen's pro forma operating expenses that the Commission has traditionally removed for rate-making purposes. Owen agreed that these expenses, which total $67,571, are contrary to past Commission decisions and, therefore, should be removed from its operating expenses for rate-making purposes.[7] These expenses are contained in Table 2 below.

Table 2: Owen's Agreed-to Expense Adjustments		
Advertising - Key Account Golf	$	850
Key Account Outings & Sponsorships	$	15,221
KAEC Meeting - Hotel	$	1,780
Congressional Meeting - Airfare	$	1,079
Congressional Meeting - Hotel	$	4,287
Advertising - Home Town Coop.	$	1,267
Advertising - Balloon Glow	$	1,267
Washington Youth Tours	$	4,800
Sponsorships for Communities	$	1,000
Dues – Civic Organizations	$	693
Advertisement - Halloween Safety	$	800
Dues & Subscriptions - Civic	$	1,078
Donations	$	100
Scholarships Awarded by Owen	$	27,000
Insurance - Retired Executive	$	745
Penalty - Late Sales Tax Penalty	$	5,604

The Commission finds that the above adjustments totaling $67,571 are reasonable and should be accepted. Accordingly, the Commission has decreased Owen's pro forma operating expenses by $67,571.

Year-End Customer Annualization Adjustment

Owen proposes to increase revenue by $61,939 to reflect the annualization of the end-of-period customer levels for the following customer classifications: Schedule 1

[7] Brief for Owen at 10 and Owen's response to the Initial Request for Information of the AG, Item 35.

Farm and Home; Schedule 1 Small Commercial; Schedule II Large Power; Schedule XI Large Industrial Rate LPB1; Schedule XIII Large Industrial Rate LPB2; Schedule XIV Large Industrial Rate LPB; and Schedule 2A Large Power T-O-D.[8]

The AG requested that Owen expand its year-end annualization adjustment to include Schedule III Security Lights, Schedule OLS, and Envirowatts in the net revenue calculations. In its response, Owen determined that if these customer classifications are included in the calculation then the proposed adjustment would be $192,110,[9] an increase of $130,171 above the $61,939 increase proposed by Owen. The AG recommended that the Commission increase Owen's pro forma other electric revenue by $130,171 to reflect all customer classifications in the annualization adjustment.[10]

The Commission finds that it is reasonable to adjust all customer classes to reflect the end-of-period customer levels. Accordingly, the Commission will increase Owen's proposed adjustment of $61,939 by an additional $130,171.

National Rural Electric Cooperative Association ("NRECA") Annual Meeting

The AG objects to Owen's inclusion of $8,500 in pro forma operating expenses for the cost of those non-qualifying directors who attended the 2007 NRECA Annual Meeting.[11] Six of Owen's seven directors attended the 2007 NRECA Annual Meeting at

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[8] Application, Exhibit 16.

[9] Owen's response to the Initial Request for information of the AG, Item 7.

[10] AG's Post Hearing Brief at 3.

[11] Id. at 8.

a total cost of $14,567.[12] The AG argues that the Commission has historically "only allowed expenses for the cooperatives' NRECA representative and their alternate."[13]

Owen claims that "the NRECA annual meeting is a combination of training and educational seminars for directors during the day and organizational activities in the evenings."[14] Owen further claims it is imperative that its directors attend these meetings in order to stay informed and keep abreast of issues facing the electric industry, particularly in light of changes in economic conditions, environmental and legal issues, technological advances, and the potential for deregulation.[15] Owen asserts that it should be allowed to recover the costs for all of its directors who attended the 2007 NRECA Annual Meeting, contending that its directors can make more informed and intelligent decisions as a result of the training received at the NRECA Annual Meetings–all to the benefit of Owen's members.[16]

In Case No. 1992-00560, the Commission found that, "for rate-making purposes, the practice of including the cost of sending all directors to meetings and conferences is excessive."[17] Accordingly, the Commission denied the expense for directors who were not the designated delegate or alternate, finding that most cooperatives send only two

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[12] Owen's Post Hearing Information Response, Item 2.

[13] AG's Post Hearing Brief at 8.

[14] Owen's response to the AG's Initial Request for Information, Item 28.

[15] Owen's response to the Commission Staff's Third Request for Information, Item 3(d).

[16] Id.

[17] Case No. 1992-00560, *Salt River Electric Cooperative Corp.* (Ky. PSC Sep. 28, 1993) at 11.

to three directors and that these directors then share the information learned at the meeting with the other directors upon their return.[18]

Six of Owen's directors attended the NRECA Annual Meeting. Because Owen's original designated delegate was unable to attend, the alternate attended the 2007 NRECA meeting on his behalf. In its post-hearing responses, Owen did not identify any of the other five directors who attended the 2007 NRECA meeting as being the new alternate. The Commission is not persuaded by Owen's argument concerning the benefit provided to the ratepayers when several directors receive identical training. The Commission finds that Owen's pro forma operating expenses should be reduced by $12,460 to remove the expense for those directors who had not been designated as the alternate delegate to attend the 2007 NRECA meeting.

In its post-hearing responses, Owen stated that it paid $3,962 in 2007 for its directors to attend the 2008 NRECA Annual Meeting. The Commission will further reduce Owen's pro forma operating expenses by $3,962 to eliminate the test-period expenses incurred for directors to attend the 2008 NRECA Annual Meeting. This results in a total adjustment for the NRECA Annual Meetings of $16,422.

Billboard at the Kentucky Speedway

Owen included in its pro forma operating expenses $10,000 for the cost of a billboard at the Kentucky Speedway.[19] According to the AG, the general contact information contained on the billboard clearly promotes Owen and does not provide any information beyond what is available to the ratepayers contained in the telephone book

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[18] Id.

[19] AG's Post Hearing Brief at 6.

or in their monthly bills.[20] The AG argues that the expenses for promotional advertising are contrary to past Commission precedent in that they are expressly disallowed for inclusion in rates pursuant to 807 KAR 5:016, Section 4(1)(b). Accordingly, the AG argues that Owen's pro forma operating expenses should be reduced by $10,000 to remove the cost of the billboard.

807 KAR 5:016, Section 1, states that the purpose of this regulation "is to insure that no direct or indirect expenditures may be includable in a gas or electric utility's cost of service for rate-making purposes which are for promotional advertising, political advertising or institutional advertising." 807 KAR 5:016, Section 2(1), further provides that "[n]o advertising expenditure of a utility shall be taken into consideration by the commission for the purpose of establishing rates unless such advertising will produce a material benefit for the ratepayers."

Based upon the requirements of the above-mentioned regulations, the Commission is in agreement with the AG in that Owen has failed to show that the information contained on the billboard provides material benefit to its ratepayers. Accordingly, the Commission is reducing Owen's pro forma operating expenses by $10,000 to eliminate the cost of the billboard.

Retirement and Security Expense

Using normalized wages of $7,172,880 and a composite rate of 18.08 percent, Owen calculated a pro forma retirement and security expense of $1,296,857, which is an increase of $151,534 above the test-period level.[21] In response to an information

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[20] Id. at 7.

[21] Application, Exhibit 7, Retirement and Security.

request, Owen calculated a revised retirement and security expense of $1,294,957 using the pro forma base wages for non-union and union employees and the actual rates of 18.64 percent for non-union employees and 17.23 percent for union employees.[22] The AG recommended that the Commission reduce Owen's pro forma operating expenses by $1,900 to reflect the revised amount. Upon review of Owen's response, the Commission finds that the revised retirement and security expense is reasonable and further finds that Owen's pro forma retirement and security expense of $1,296,857 should be reduced by $1,900.

Automated Meter reading ("AMR") Consulting Fees

The AG objects to Owen's request to include $23,997 in pro forma operating expense for consulting fees associated with the AMR program.[23] Owen acknowledges that the AMR consulting fees are nonrecurring but maintains that some additional level of consulting fees will occur in the future. The AG argues that Owen has not shown that the level of future costs will equal the reported test-period amount.[24] The AG concludes that, since future consulting fees are not currently known and measurable, the $23,997 of consulting fees recorded in the test period should be removed.[25]

The Commission is in agreement with the AG that the consulting fees should be removed from Owen's pro forma operating expenses; however, the Commission views

[22] Owen's response to the Commission Staff's Third Request for Information, Item 13.

[23] AG's Post Hearing Brief at 6.

[24] Id.

[25] Id.

the consulting fees as an overhead construction cost that should be capitalized and depreciated over the useful life of the automated meters. Depreciating the AMR consulting fees of $23,997 over a 15-year depreciation life will result in an increase to depreciation expense of $1,601.[26] Therefore, the Commission is reducing Owen's pro forma operating expenses by a net amount of $22,396.

Employee Coffee

Included in Owen's operating expenses is the cost of providing coffee to its employees of $1,767. Owen contends that providing coffee promotes workforce efficiency and productivity.[27] Owen argues that if its "outside employees were to stop and get coffee on their own each morning, then line trucks, bucket trucks, and service trucks would be attempting to get in small rural locations and take extra time to get to work, thus being very inefficient every day."[28]

According to the AG, Owen's employees could get their own coffee on their way to work since they do not drive work vehicles home.[29] The AG argues that proper employee management should prevent the utility vehicles from making prohibited stops for personal errands at the ratepayers' expense.[30] The AG states that the cost of coffee before work breaks should not be borne by ratepayers and that the Commission has

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[26] $23,997 (AMR Consulting Fees) x 6.67% (Depreciation Rate) = $1,601.

[27] Owen's response to the AG's Second Request for Information, Item 10.

[28] Id.

[29] AG's Post Hearing Brief at 7-8.

[30] Id.

traditionally disallowed this type of expense for rate-making purposes.[31] For these reasons the AG argues that Owen's pro forma expenses should be reduced by $1,767 to eliminate this employee fringe benefit.[32]

The Commission agrees with the AG's position concerning recovery of the cost of providing coffee to Owen's employees. In Case No. 1995-00554, the Commission found that these types of employee-related expenses may benefit employer/employee relations; however, such costs should not be borne by the ratepayer.[33] The practice used by many employers is to provide their employees with coffee but require the employees to pay for their coffee through contribution to a coffee fund. Therefore, the Commission will eliminate the employee coffee fringe benefit by reducing pro forma operating expenses by $1,767.

Temporary Labor

Owen included $9,379 in its pro forma operating expenses for temporary labor. According to Owen, the temporary labor is required to cover shortages at its call center and mail room.[34] The AG states that Owen has included a full complement of full-time employees that are working 2,080 hours per year as well as one part-time employee.[35] Because employee sick and vacation benefits are included in the pro forma operating

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[31] Id.

[32] Id.

[33] Case No. 1995-00554, *Kentucky-American Water Co.* (Ky. PSC Sep. 11, 1996) at 43.

[34] March 25, 2009 hearing video, Witness - Rebecca Witt, 1:24 pm.

[35] AG's Post Hearing Brief at 8.

expenses, the AG contends that the costs for the employee shortages are accounted for in the application.[36]

The Commission disagrees with the AG's position. If an employee is absent from work due to illness or vacation, the duties of that employee must still be performed. Therefore, including the cost of temporary labor and employee sick or vacation time is not double recovery. Accordingly, the Commission accepts Owen's inclusion of temporary labor in pro forma operating expenses.

Short-Term Interest Expense

Owen reports test-period short-term interest expense of $689,738.[37] Owen estimated that its requested rate increase would be sufficient to allow it to repay one-half of the outstanding short-term note payable and, therefore, it proposed to reduce short-term interest expense by one-half or $344,869.[38] However, Owen later agreed that since $10 million of the proceeds of the November 2007 Rural Utilities Service ("RUS") loan was used to reduce short-term debt, it would be more appropriate to use the short-term debt balance as of December 31, 2007 to calculate the pro forma short-term interest expense.[39] Using its December 31, 2007 short-term debt balance, Owen calculated revised short-term interest expense of $366,140, an increase of $21,271 above the amount it originally requested.[40]

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[36] Id.

[37] Application, Exhibit 5 at 3.

[38] Id.

[39] Owen's response to the AG's Second Request for Information, Item 4.

[40] Id.

The AG argues that Owen's test-period short-term interest expense should be reflected at $366,140 as opposed to the $689,738 reported by Owen.[41] According to the AG, Owen assumed that one-half of its short-term debt would be repaid from the rate increase resulting from this instant rate case and that the Commission should also use this assumption.[42] Adopting this assumption, the AG argues that the pro forma expense should be one-half of $366,140, or $183,070, which results in a reduction to Owen's pro forma short-term interest expense of $161,799.

The Commission finds that the methodology used by Owen in its original adjustment is based upon budgetary assumptions. There are numerous factors that impact a utility's short-term debt balance. Owen's original adjustment only considers the expected impact the proposed rate increase could have on its future short-term debt balance without taking into consideration the effective date of the new rates or the impact future construction projects will have on its short-term debt issuances. For these reasons the Commission finds that adjusting short-term interest expense based on budget projections fails to meet the rate-making criteria of known and measurable. Therefore, the Commission will deny both Owen's original adjustment and the AG's recommended revision. The Commission finds that using Owen's end-of-period short-term debt balance is reasonable. This will increase Owen's pro forma short-term interest expense by $21,271, from $344,869 to $366,140.

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[41] AG's Post Hearing Brief at 5.

[42] Id.

Interest on Customer Deposits

Owen reports test-period interest expense on customer deposits of $130,051. Relying upon Case No. 1999-00176,[43] the AG argues that the interest on customer deposits should be removed from Owen's pro forma operating expenses.[44]

Owen contends that the case relied upon by the AG is distinguishable from the instant case. Owen points out that Case No. 1999-00176 involved an investor-owned gas utility that was not subject to the RUS and the National Rural Utilities Cooperative Finance Corporation requirements to which Owen is subject as a non-profit rural electric cooperative.[45] Owen states that its customer deposits are recorded as a current liability rather than income, as the customer deposits are intended to serve as security and not as a prepayment of income.[46] Owen further states that it is not aware of any proceeding involving an electric cooperative where the Commission has disallowed rate recovery of interest on customer deposits.[47]

Given that Owen's revenue requirement is based upon a Times Interest Earned Ratio ("TIER") rather than a return on rate base, the Commission finds that the matching principle contained in the case cited by the AG does not apply. Furthermore, unlike investor-owned utilities, interest income is included in the revenue requirement

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[43] Case No. 1999-00176, *Delta Natural Gas Company, Inc.* (Ky. PSC Dec. 27, 1999).

[44] AG's Post Hearing Brief at 6.

[45] Brief for Owen at 9.

[46] Id.

[47] Id. at 10.

calculation for electric cooperatives. A mismatch will occur if the interest expense paid by Owen to its customers is removed from expenses while the interest income earned on those customer deposits remains in Owen's operating revenues. For these reasons, the Commission finds no basis to adjust Owen's pro forma operating expenses as argued by the AG.

Summary

Based on the pro forma adjustments found reasonable herein, the Commission finds that Owen's pro forma operations should be as follows:

	Test-Period Operations	Pro Forma Adjustments	Pro Forma Operations
Operating Revenues	$ 142,992,351	$ (14,792,664)	$ 128,199,687
Operating Expenses	139,642,989	(16,139,124)	123,503,865
Net Operating Income	$ 3,349,362	$ 1,346,460	$ 4,695,822
Interest on Long-Term Debt	3,823,761	478,648	4,302,409
Interest Expense-Other	819,788	(323,598)	496,190
Other Income and (Ded.)-Net	468,130	101,616	569,746
Net Income	$ (826,057)	$ 1,293,026	$ 466,969

REVENUE REQUIREMENTS

The rate of return earned on Owen's net investment rate base established for the test year was 2.51 percent.[48] Owen requested rates that would result in a TIER of 2.00X, excluding GTCCs and a rate of return of 6.66 percent on its proposed rate base of $129,193,682.[49] Owen proposes an increase in revenues of $4,064,395 to achieve the 2.00X TIER excluding GTCCs.[50]

[48] Application Exhibit K at 1.

[49] Id.

[50] Id. Exhibit S at 2.

Owen's TIER excluding GTCCs for the test period was 0.78X.[51] For the calendar years 2005 and 2006, Owen's TIERs were 1.28X and 2.39X, respectively.[52] After taking into consideration the allowable pro forma adjustments, Owen would achieve a 1.109X TIER excluding GTCCs without an increase in revenues.

Neither the AG nor Gallatin offered a position on the use of the 2.00X. The Commission finds that the use of a 2.00X TIER is reasonable for Owen. In order to achieve the 2.00X TIER, Owen would need an increase in annual revenues of $3,835,440.

Based upon the pro forma adjustments found to be reasonable, the Commission has determined that an increase in Owen's revenues of $3,835,440 would result in a TIER of 2.00X. The additional revenue should produce net income of $4,302,409 and, based on the net investment rate base of $129,182,644 found reasonable herein, should result in a rate of return on rate base of 6.66 percent.

PRICING AND TARIFF ISSUES

Cost of Service

Owen filed a fully allocated cost-of-service study ("COSS") for the purpose of determining the cost to serve as well as the revenue allocation for all rate classes. The COSS indicates that the Farm and Home, Small Commercial, Security Lights, Outdoor Lighting Service and Special Outdoor Lighting Service customer classes all produce revenues insufficient to meet the costs to serve those classes, while the large power and industrial rate classes produce revenues in excess of the costs Owen incurs to

[51] Id. at 6.

[52] Id.

serve those classes. Neither intervenor filed a COSS nor argued that the COSS filed by Owen was unreasonable.

Having reviewed Owen's COSS, the Commission finds it to be acceptable for use as a guide in allocating the revenue increase awarded herein.

Revenue Allocation and Rate Design

Owen proposes an overall revenue increase of $4,064,395, or 3.2 percent, with increases of six percent for the Farm and Home and Small Commercial classes, 37.9 percent for the Security Lights class, 5.5 percent for the Outdoor Lighting class, and 30.0 percent for the Special Outdoor Lighting class. Owen proposes no increase in revenues for its other classes.

Owen proposes increases only to the customer charges of both the Farm and Home and Small Commercial classes with no changes in energy charges. Owen proposes an increase from $5.64 to $11.20 in the Farm and Home customer charge and from $5.64 to $13.44[53] in the Small Commercial customer charge. Owen argues that this change in rate design will better match its revenues with its costs of service and will align the interests of the cooperative and its members with regard to energy innovation, efficiency, conservation, demand response and distributed generation. Because a large portion of its member-related fixed costs are currently recovered through its energy charges, Owen asserts that it will not be able to fully recover its fixed costs when there is a reduction in kWh sales due to the potential implementation of any energy efficiency

[53] The proposed Small Commercial customer charge was stated as $13.48 in the application and in Owen's brief filed on April 22, 2009; however, in response to Item No. 7 in Staff's Third Data Request, Owen agreed that the amount should have been $13.44.

programs. Owen states that it is not reasonable to pursue such programs when the resulting reduction in sales has a negative financial impact on the utility. This issue will be addressed in more detail in the next section of this Order.

The AG states that the energy portion of the bill is the only portion over which the customer has any control. He claims that to allow the customer charge to climb too high would discourage customers from individual conservation efforts. The AG states that with a higher customer charge, the customer loses the incentive to conserve energy because no matter what actions a customer takes to do so, the effect on the bill would be insignificant. The AG further argues that, by allowing Owen to increase its customer charge as proposed, the utility is guaranteed its income whether management operates the utility prudently or not. The AG concludes his argument by calling for gradualism with respect to the increase in customer charges.

The difference between the $4,064,395 proposed by Owen and the $3,835,440 approved in this Order is $228,955. The COSS shows that, at Owen's proposed rates, the Farm and Home class and Small Commercial class would provide rates of return of 5.38 and 4.97 percent, respectively, while combining the results for the three lighting schedules shows that the lighting class as a whole would provide a rate of return of negative 0.7 percent. Based on these results, the Commission finds that the increases for the lighting classes should be allocated as proposed by Owen while the proposed increases to the Farm and Home and Small Commercial classes should be adjusted downward, proportionately, to generate the revenue increase approved herein. The Commission, based on the results of Owen's COSS and mindful of the throughput incentive which is inherent in Owen's existing rate design, accepts Owen's proposal to allocate the Farm and Home and Small Commercial class revenue increases entirely to their respective customer charges.

In Case No. 2008-00421,[54] Owen requested a pass-through of its increase in wholesale rates from EKPC on a COSS basis. Owen's pass-through was not approved on a COSS basis because the Commission could not rule on the reasonableness of the COSS in that case. Accordingly, the pass-through was approved in that proceeding on a proportional basis in the Commission's Interim Order entered March 31, 2009. Concurrent with this Order, the Commission is issuing a final Order in that case, which, based on its decision in this proceeding to accept Owen's COSS as a guide for allocating the increase granted herein, will approve Owen's pass-through of wholesale power expenses on a COSS basis. Accordingly, the rates approved herein reflect the approval of $6,462,157 in increases to all classes to recover Owen's increase in wholesale power costs plus the $3,835,440 approved in this general rate case to those classes whose revenues are insufficient to meet cost of service.

OTHER ISSUES

Energy Efficiency and Demand-Side Management ("DSM")

As previously stated, on January 27, 2009, shortly after being employed as Owen's President and CEO, Mr. Stallons submitted pre-filed testimony. Although his testimony supported the overall need for the rate increase requested, the major focus of Mr. Stallons' testimony addressed the need for modifications to Owen's rate design.

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[54] Case No. 2008-00421, *Owen Electric Cooperative Corporation* (Ky. PSC March 31, 2009).

Mr. Stallons testified that "Owen's current retail rate design does not align the interests of the Cooperative and its members with respect to energy innovation, efficiency, conservation, and demand response efforts."[55] Mr. Stallons described the results of Owen's COSS, which indicated that the residential customer charge should be $21.92 per month rather than the current charge of $5.64 per month and which does not cover member-related costs or any margins. Thus, according to Mr. Stallons, Owen must recover "all of its margins and a significant portion of its member related fixed costs through an energy charge assessed on a kWh basis"[56] and "any reduction in kWh sales due to energy innovation, efficiency, conservation, and demand response efforts results in the Cooperative recovering less of its fixed cost and margin, which financially harms the Cooperative."[57] This results in the "thoughput incentive" where, between rate cases, a utility has a financial incentive to maximize sales and increase its profits.[58] According to Mr. Stallons, the simplest way to mitigate the throughput incentive is to increase the customer charge to a level that is justified based on the cost of service to ensure that the revenue stream is not linked to sales.[59]

Owen's current energy-efficient programs consist of distributing compact fluorescent light bulbs, performing residential and commercial energy audits, offering rebates on energy efficient home building practices and appliances, and conducting

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[55] Direct Testimony of Mark A. Stallons, at 4.

[56] Id.

[57] Id.

[58] Id. at 5.

[59] Id.

energy efficiency seminars and workshops.[60] In addition, Owen began offering direct load control of water heaters and air conditioners in October 2008 as part of EKPC's efforts to implement a direct load control program for its member systems.[61] Owen's energy efficiency programs' budget for 2007 was $118,967 and for 2008 was $200,654.[62] This represents an annual expenditure of approximately of $2.12 for 2007 and $3.55 for 2008 for each of Owen's residential and small commercial customers.[63]

In response to an AG information request, Owen responded that it is in the process of developing an energy innovation plan which it intends to present to its Board of Directors by November 1, 2009. According to Owen, the plan will align its culture and business model to meet its members' need to manage their energy costs, preserve resources, and consume energy wisely by implementing a culture of energy innovation. Among other things, Owen plans to decouple its revenue from kWh sales; increase its customer charge to cover fixed costs; investigate and develop progressive rate designs that encourage energy innovation (this includes consideration of reduced energy charges, time of use rates, and inclining energy block rates); investigate technological opportunities and develop a plan and pilot project to provide members with energy

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[60] Id. at 12.

[61] Owen Electric tariff, Sheet No. 124A, Direct Control of Water Heaters Program, Direct Control of Air Conditioners Program, Issued October 22, 2008, Effective October 2, 2008.

[62] Response to the AG's Third Request for Information, Item 2 at 2.

[63] In its 2007 Annual Report, Owen reported an average of 54,003 residential customers and 2,016 small commercial customers (56,019 total). In its 2008 Annual Report, Owen reported an average of 54,427 residential customers and 2,086 small commercial customers (56,513 total).

usage data and pricing information that enables them to manage their kWh consumption, their monthly energy bill, and their home comfort; develop rate and pricing strategies to minimize rate class subsidization; and to promote distributed generation where it is economically and technically feasible.[64] At the hearing, Mr. Stallons stated that he would be a "strong advocate" on the EKPC board for DSM programs that reduce peak load.[65]

In his post-hearing brief, the AG indicates support for energy efficiency but does not support the requested increase to the residential customer charge proposed by Owen. The AG recommends that the Commission employ the principle of "gradualism" in applying an increase to the customer charge and balance stakeholder interests rather than utilize the "flash cut" approach proposed by Owen.[66]

The Commission recognizes the concerns of both the AG and Owen. As we noted in several recent Orders,[67] the Commission believes that conservation, energy efficiency and DSM programs are very important and such programs will become more cost-effective as additional restrictions are placed on coal-fired generation. Although Owen has a number of DSM programs in place, the Commission believes that it is appropriate to encourage Owen, and all other electric energy providers, to make a

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[64] Response to the AG's Third Request for Information, Item 3 at 2.

[65] Transcript of Evidence at 65.

[66] AG's Post Hearing Brief at 13-14.

[67] Case No. 2008-00254, *Grayson Rural Electric Cooperative Corporation* (Ky. PSC June 3, 2009); Case No. 2008-00401, *Big Sandy Rural Electric Cooperative Corporation* (Ky. PSC June 3, 2009); Case No. 2008-00030 *Farmers Rural Electric Cooperative* (Ky. PSC June 10, 2009).

greater effort to offer cost-effective DSM and other energy efficiency programs. As stated in his prefiled testimony, responses to data requests, in his direct testimony at the public hearing, and as noted earlier in this Order, Mr. Stallons plans to develop an "energy innovation" plan to supplement Owen's 2010 strategic plan for presentation to the Board of Directors by November 1, 2009. The Commission expects Mr. Stallons to follow through on the development of this plan and directs Owen to submit a detailed report addressing its future plans for energy efficiency and demand response to the Commission no later than December 31, 2009.

As discussed earlier in this Order, with the exception of the difference between the increase requested by Owen and the increase authorized herein, the Commission has accepted the rate design changes proposed by Owen based on its COSS. If, after developing its "energy innovation" plan, Owen still believes that its rate design does not support energy efficiency and DSM activities, it should consider filing an application to adopt a DSM surcharge or to revise its rate design.

SUMMARY

The Commission, after consideration of the evidence of record and being otherwise sufficiently advised, finds that:

1. The rates set forth in the Appendix to this Order are the fair, just, and reasonable rates for Owen to charge for service rendered on and after the date of this Order.

2. The rate of return and TIER granted herein are fair, just, and reasonable and will provide for Owen's financial obligations.

3. The rates proposed by Owen would produce revenue in excess of that found reasonable herein and should be denied.

4. Owen should prepare a detailed report addressing its future plans for energy efficiency and demand and submit its report to the Commission no later than December 31, 2009.

IT IS THEREFORE ORDERED that:

1. The rates proposed by Owen are denied.

2. The rates in the Appendix to this Order are approved for service rendered by Owen on and after the date of this Order.

3. Within 20 days of the date of this Order, Owen shall file new tariff sheets setting forth the rates and charges approved herein and reflecting their effective date and that they were authorized by this Order.

4. Owen shall prepare a detailed report addressing its future plans for energy efficiency and demand and shall submit its report to the Commission no later than December 31, 2009.

By the Commission

ENTERED
JUN 25 2009
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2008-00154 DATED JUN 2 5 2009

The following rates and charges are prescribed for the customers in the area served by Owen Electric Cooperative, Inc. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of the Commission prior to the effective date of this Order.

SCHEDULE I
FARM AND HOME

Customer Charge per Month	$	10.87
Energy Charge per kWh	$	.08063

SCHEDULE I
FARM AND HOME – OFF-PEAK MARKETING RATE

Energy Charge per kWh	$	.04838

SCHEDULE I
SMALL COMMERCIAL

Customer Charge per Month	$	12.83
Energy Charge per kWh	$	.08055

SCHEDULE I – OLS
OUTDOOR LIGHTING SERVICE

Monthly Rates:		
100 Watt High Pressure Sodium	$	9.69
Cobrahead Lighting		
100 Watt High Pressure Sodium	$	12.62
250 Watt High Pressure Sodium	$	17.02
400 Watt High Pressure Sodium	$	20.99
Directional Lighting		
100 Watt High Pressure Sodium	$	11.81
250 Watt High Pressure Sodium	$	14.37
400 Watt High Pressure Sodium	$	18.09
Rate for One Additional Pole if Required	$	4.69

SCHEDULE II – SOLS
SPECIAL OUTDOOR LIGHTING SERVICE

Traditional Light with Fiberglass Pole	$	12.47
Holophane Light with Fiberglass Pole	$	14.84

SCHEDULE III – SOLS
SPECIAL OUTDOOR LIGHTING SERVICE

Energy Rate for each type of light per kWh	$	.053274

SCHEDULE II
LARGE POWER

Customer Charge per Month	$	20.50
Demand Charge per Month per kW	$	5.90
Energy Charge per kWh	$	.05831

SCHEDULE III
SECURITY LIGHTS

Flat rate per light per month as follows:		
On Existing Pole where 120 Volts is available	$	7.91
One Pole Added	$	9.65
Two Poles Added	$	11.39
Three Poles Added	$	13.13
Four Poles Added	$	14.88
Transformer Required	$	.67

SCHEDULE VIII
LARGE INDUSTRIAL RATE – LPC1

Customer Charge per Month	$	1,464.04
Demand Charge per Month per kW - Contract	$	6.81
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.04383
For all kWh in excess of 425 hrs per kW of billing demand	$	.03975

SCHEDULE IX
LARGE INDUSTRIAL RATE – LPC2

Customer Charge per Month	$	2,927.05
Demand Charge per Month per kW - Contract	$	6.81
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.03908

For all kWh in excess of 425 hrs per kW of billing demand	$	.03750

SCHEDULE X
LARGE INDUSTRIAL RATE – LPC1-A

Customer Charge per Month	$	1,464.04
Demand Charge per Month per kW - Contract	$	6.81
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.04146
For all kWh in excess of 425 hrs per kW of billing demand	$	.03872

SCHEDULE XI
LARGE INDUSTRIAL RATE – LPB1

Customer Charge per Month	$	1,464.04
Demand Charge per Month per kW - Contract	$	6.81
Demand Charge per Month per kW - Excess	$	9.47
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.04383
For all kWh in excess of 425 hrs per kW of billing demand	$	.03975

SCHEDULE XII
LARGE INDUSTRIAL RATE – LPB1-A

Customer Charge per Month	$	1,464.04
Demand Charge per Month per kW - Contract	$	6.81
Demand Charge per Month per kW - Excess	$	9.47
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.04146
For all kWh in excess of 425 hrs per kW of billing demand	$	.03872

SCHEDULE XIII
LARGE INDUSTRIAL RATE – LPB2

Customer Charge per Month	$	2,927.05
Demand Charge per Month per kW - Contract	$	6.81
Demand Charge per Month per kW - Excess	$	9.47
Energy Charge per kWh		
For all kWh, first 425 hrs per kW of billing demand	$	.03908
For all kWh in excess of 425 hrs per kW of billing demand	$	.03750

SCHEDULE XIV
LARGE INDUSTRIAL RATE – LPB

Customer Charge per Month	$	1,464.04
Demand Charge per Month per kW - Contract	$	6.81

Demand Charge per Month per kW - Excess	$	9.47
Energy Charge per kWh	$	.04537

SCHEDULE 1B

FARM AND HOME – TIME OF DAY

Customer Charge per Month	$	17.69
On-Peak Energy Charge per kWh	$	.094950
Off-Peak Energy Charge per kWh	$	.049244

SCHEDULE 1C

SMALL COMMERCIAL – TIME OF DAY

Customer Charge per Month	$	23.58
On-Peak Energy Charge per kWh	$	.091450
Off-Peak Energy Charge per kWh	$	.049244

SCHEDULE 2A

LARGE POWER – TIME OF DAY

Customer Charge per Month	$	59.00
On-Peak Energy Charge per kWh	$	.095320
Off-Peak Energy Charge per kWh	$	.053543

NONRECURRING CHARGES

Return Check	$	25.00
Collection	$	30.00
Disconnect	$	60.00
Meter Test	$	50.00
Overtime	$	80.00

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President
Owen Electric Cooperative, Inc.
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Owenton, KY 40359

Affiant, Mark A. Stallons, states that the answers given by him to the foregoing questions are true and correct to the best of her knowledge and belief.

Mark A. Stallons, President & CEO

Subscribed and sworn to before me by the affiant, Mark A. Stallons, this 29th day of December, 2009.

Notary Laura M. Scroggins
State-at-Large

My Commission expires May 2, 2012.

Exhibit 1

Owen Electric Cooperative
PSC Energy Innovation Update
December 29, 2009

At Owen Electric Cooperative's April Board Meeting we revised our 2009 Strategic Plan to include Challenge 6 – Improve Member Satisfaction. In September the Board of Directors conducted an all day strategic planning session and developed an updated plan for 2010 which was approved at our December 2009 Board Meeting. A five pronged strategy was developed with key action items identified to achieve the strategy and meet the overall challenge of improving member satisfaction. Please refer to Exhibit A for a copy of challenge 6 of the 2010 strategic plan.

The premise underlying the development of this strategy is that climate change legislation, increasing environmental regulation, fuel volatility, and increasing power supply cost pressures over the next five years may put downward pressure on member satisfaction as they struggle to adjust to increasing power bills. The precise timing and the severity of the cost impact is dependant on market forces, legislators, and regulators. The success of our mitigating strategy is dependant on the pace of developing energy innovative technologies. Given the above it is prudent to develop an aggressive strategy to meet this challenge. In order to be successful our strategy must be flexible and subject to modification as technology, regulations, and legislation develop. The implementation of our strategy will be correlated to the development, implementation, and timing of legislative, regulatory, subsequent market cost pressures, and developing innovative energy technologies. Our challenge is to improve member satisfaction in spite of subsequent market pressures, to be prepared, and to have tools developed and ready that will help our members manage their power bills.

The challenge, strategies, and key action items are as follows:

<u>2010 Challenge 6 – Member Satisfaction</u>

Strategy A – Embrace Energy Innovation

Key Action Items

1. Align the culture and business model of Owen Electric Cooperative (OEC) to fully meet our members need to manage their energy costs, preserve resources, and consume energy wisely by implementing a culture of "Energy Innovation" within Owen Electric Cooperative and its membership.
2. Investigate, develop, and implement energy innovation pilot projects such as home energy efficiency improvements. Measure and verify the energy and demand savings.
3. Develop and understand the relationship between energy innovation member incentives and kWh and kW demand savings. Collect and organize data in such a manner that we begin to understand how increasing or decreasing member incentives affect kWh or kW demand savings.

4. Implement a Smart Home pilot project to provide our members with energy usage data and pricing information that enables our members to manage their kWh consumption, their monthly energy bill, and their home comfort.
5. Implement a Smart Grid pilot project including (1) upgrading our existing SCADA (supervisory control and data acquisition) system, (2) installing an automated capacitor control pilot project, (3) installing a self-healing grid pilot project, and (4) enhancing our communications network capacity and reliability.

Strategy B – Develop and implement an Education Plan

Key Action Items

1. Develop and implement an education plan to communicate, educate, and encourage energy innovation. Promote controlling costs, preserving resources, and using energy wisely. Promote energy innovation as a tool to mitigate rising energy costs.

Strategy C – Implement innovative and financially stable rate designs

Key Action Items

1. Decouple our revenue from kWh sales by increasing our customer charge to cover our fixed costs. This will allow OEC to become kWh sales neutral and to build a culture of energy innovation where we have no financial disincentives toward energy innovation.
2. Investigate and develop innovative rate designs that encourage energy innovation rather than increasing energy sales. A few possible rate options include but are not limited to increased customer charges coupled with reduced energy charges and inclining energy blocks, time of use, critical peak pricing, pre-pay metering, and a customer charge component to fund energy innovation.

Strategy D – Collaborate with Cooperative Partners

Key Action Items

1. Partner and collaborate with East Kentucky Power Cooperative (EKPC), National Rural Electric Cooperative Association (NRECA), Department of Energy (DOE), National Rural Utilities Cooperative Financial Cooperative (NRUCFC), CoBank, Rural Utility Services (RUS), Rural Electric Management Development Council (REMDC), and other cooperative partners to develop a comprehensive energy innovation plan that includes all aspects of energy from the generation plant to the member's home.
2. Develop rate and pricing strategies to promote energy innovation and minimize rate class subsidization.
3. Promote distributed generation where it is economically and technically viable. Develop rate and pricing strategies to minimize rate class subsidization.

4. Investigate alternative fuel adjustment clause (FAC) formulas that reduce volatility and resolve timing issues.

Strategy E – Secure funding for the Energy Innovation Plan

Key Action Items

1. Identify and utilize all federal and state funding opportunities available to encourage energy innovation.
2. Investigate and utilize a mix of internal cooperative, RUS, NRUCFC, and CoBank funding.

Status Report:
As of December 31, 2009 the status of our initiative is as follows.

Strategy 6A1 – Align the culture and business model with Energy Innovation

The alignment of our culture and business model from dependency on increasing energy sales to one of energy innovation is ongoing and will happen over the next one to five years as we implement strategies 6A through 6E defined above.

Strategy 6A2 - Investigate, develop, and implement energy innovation pilot projects

In partnership with East Kentucky Power Cooperative we are engaged in several energy innovative projects including a water heater incentive program with a simple saver load control switch, a geothermal and high efficiency air source heat pump incentive program, Touchstone Energy Home incentive program, Button Up and Simple Savers programs. For more information please refer to Exhibit B for details of our 2009 energy saving incentive programs.

The Button Up pilot was completed in 2009 and will be available for the entire membership in 2010. Button Up entails identifying home energy efficiency issues where significant energy is lost and providing financial assistance to improve the homes energy efficiency by adding insulation, caulking, and other home improvements to increase the homes efficiency.

The Simple Saver program allows members to reduce their peak hourly energy demand by agreeing to allow their water heaters and air conditioning units to be controlled when power prices are above normal. To date we have approximately 350 members participating in the Simple Saver program and approximately 475 load control devices installed.

Strategy 6A3 - Develop and understand the relationship between energy innovation member incentives and kWh and kW demand savings

We will be developing measurement tools to determine how successful each member incentive program has been in regards to encouraging participation in our energy innovation programs. Incentives and programs that are not successful will be discontinued and those that are successful will be continued. Promotional efforts will be measured based upon member participation.

As more effective measurement and verification technologies develop we will work to improve our ability to quantify the amount of energy and capacity saved or shifted in time. Results from our 2009 Button-Up pilot program showed an average reduction of 8,389 BTU's per house; 2.45 KW reduction per house, at an average cost of $1,810 per house.

Additionally, during 2009 we conducted approximately 400 in-depth energy audits in our member's homes. In concert with our formal energy audits, our representatives are constantly involved with consultations with our membership concerning energy efficiency. Supplementing these efforts are numerous informational resources we provide our membership that communicate all aspects of energy innovation. For more information concerning our Communications Plan please refer to Exhibit C. We plan to increase our efforts and resources in the area of energy advising to our members during 2010. An additional energy advisor position is planned for 2010 to accommodate our efforts in this area.

Strategy 6A4 & 6A5 - Develop Smart Home and Smart Grid pilot projects

In November we were awarded a grant from the Department of Energy along with 27 other electric cooperatives to develop smart grid and smart home demonstration pilot projects. Please refer to Exhibit D for a copy of the proposal submitted on our behalf by NRECA's Cooperative Research Network.

In regards to smart home development the project is in the final budget and planning stage. We are working with our vendor partners to develop a deployment plan based upon expected development of in-home energy technology. We initially plan on launching a "Beat the Peak" and "PrePay" rate to introduce proven energy in-home technology to our members. As technology develops we will introduce more complex technologies such as advanced in home displays, smart meters, smart appliances, smart thermostats, and internet energy portals. We expect to finalize an agreement with DOE by the end of the first quarter 2010.

In regard to smart grid development, Owen Electric's project will include upgrading our SCADA (Supervisory Control and Data Acquisition) system, installing an automated capacitor control pilot project, installing a self healing grid pilot project, and enhancing our communications network capacity and reliability. We are presently working with potential vendors, finalizing scope of work, material lists, and project timelines, and budgets. Similar to the Smart Home pilot we expect to finalize an agreement with DOE by the end of the first quarter 2010.

Strategy 6B – Develop and implement an Education plan

We are in the process of developing an education plan which includes demonstration projects, a communication plan, and other member and community educational efforts yet to be determined. Our communication plan was developed in concert with our 2010 strategic plan and our 2010 budget. Please refer to Exhibit C for a copy of the communication plan. We are targeting to have an education plan developed by July 1, 2010.

Strategies 6C1 & 6C2 – Redesign our rate structure to be energy sales neutral and develop rates to promote energy innovation

We are presently working with our rate consultant to develop a revenue neutral rate case including an increasing customer charge with inclining energy blocks, an energy innovative prepaid metering rate with an in home display, and a Beat the Peak in home display rate. The rate structure is designed to encourage wise energy use, to provide members with information to make wise energy decisions utilizing reliable and proven technology. We plan on filing our rate case on or before April 1, 2010.

Strategy 6D1 & 6D2 - Collaborate with our Cooperative partners to develop an energy innovation plan.

We are working in unison with East Kentucky Power Cooperative to develop cost of service power supply rates that encourage energy innovation. A rates task force was developed in August of 2009 to develop a Request for Proposal (RFP) to hire a consultant to prepare a cost of service and rate study based upon 2009 test year. The results are expected in August of 2010. In addition we are also working together on strategy 6A2 as discussed earlier to promote the Button Up and Simple Saver initiatives highlighted in Exhibit B.

We are also working together with NRECA, the Cooperative Research Network, the Department of Energy, and East Kentucky Power Cooperative on four demonstration pilot projects including a Smart Home pilot project and four Smart Grid pilot projects previously discussed in strategies 6A4 and 6A5.

Lastly we are working with our financial partners, RUS, NRUCFC, and CoBank to ensure adequate financing for our energy innovation initiative.

Strategy 6D3 - Promote distributed generation and develop and implement a solar demonstration project.

Owen is very supportive and assists our members and their consultants as requested in regards to investigating distributed generation, understanding the net metering tariff requirements, installing distributed generation, and meeting all applicable codes and regulations. In our 2010 budget we have included a solar project to educate and promote renewable energy use. The project is presently in the development and planning stage.

Strategy 6D4 – Investigate alternative fuel adjustment clause formulas

The fuel adjustment clause is a constant source of member dissatisfaction. Specifically the monthly volatility of the rate is the greatest source of member irritation. The issue is challenging in that it is complex and requires regulatory and legislative cooperation and collaboration. The issue is being discussed by East Kentucky's rate task force.

Strategy 6E – Secure Funding

Owen Electric has been awarded Department of Energy funding for Smart Grid demonstration projects and is in the process of negotiating a final agreement before launching the five year initiative. The DOE award will fund roughly half of the project with the remaining funds coming from a mix of internal sources as well as our traditional lending partners RUS, NRUCFC, and CoBank.

Conclusion

The transition from encouraging increasing energy consumption to promoting energy innovation and the wise use of energy will be challenging and will require partnering with our technology, research and development, generation, financial, and regulatory partners as well as educating, preparing, and encouraging our members to utilize the tools and take advantage of energy innovative opportunities as they become available. We look forward to the challenge, embrace it as our vision, and have made it our mission to assist our members as they choose to make wise energy choices and manage their energy use.

Exhibit A

2010 STRATEGIC CHALLENGES - 3 TO 5 YEARS

CHALLENGE 6 - Improve "Member Satisfaction"		
STRATEGY A) Embrace Energy Innovation	A) 1 Align the culture and business model of OEC to fully meet our members need to manage their energy costs, preserve resources, and consume energy wisely by implementing a culture of "Energy Innovation" within OEC and its membership.	On-going
	2 Investigate, develop, and implement energy innovation pilot projects such as home energy efficiency improvements. Measure and verify the energy and demand savings.	On-going
	3 Develop and understand the relationship between energy innovation, member incentives, and kWh and kW demand savings. Collect and organize data in such a manner that we begin to understand how increasing or decreasing member incentives affect kWh or kW demand savings.	On-going
	4 Implement smart-home pilot project to provide our members with energy usage data and pricing information that enables our members to manage their kWh consumption, their monthly energy bill, and their home comfort.	On going
	5 Implement Smart grid pilot project	
	- Finalize agreement with DOE	03/31/10
	- SCADA (supervisory control and data acquisition) system upgrade	On going
	- Installing an automated capacitor control pilot project	On going
	- Installing a self-healing grid pilot project	On going
	- Enhancing communications network capacity and reliability	12/31/10

2010 STRATEGIC CHALLENGES - 3 TO 5 YEARS

CHALLENGE 6 *(continued)* - Improve "Member Satisfaction"		
B) Education Plan	B) Implement the 2010 education plan to communicate, educate, and encourage energy innovation. Promote controlling costs, preserving resources, and using energy wisely. Promote energy innovation as a tool to mitigate rising energy costs.	On-going
C) OEC Rate Design	C) 1 Decouple our revenue from kWh sales by slowly, over a reasonable period of time, increasing our customer charge to cover our fixed costs. This will allow OEC to become kWh sales neutral and to build a culture of energy innovation where we have no financial disincentives toward energy innovation.	04/01/10
	2 Investigate and develop innovative rate designs that provide financial stability and encourage energy innovation rather than increasing energy sales. File rate case with the PSC.	04/01/10
D) Collaborate with Cooperative Partners	D) 1 Partner and collaborate with EKPC, NRECA, DOE, NRUCFC, CoBank, RUS, REMDC, and other cooperative partners to develop a comprehensive energy innovation plan that includes all aspects of energy from the generation plant to the member's home.	08/01/10
	2 Develop rate and pricing strategies to promote energy innovation and minimize rate class subsidization.	08/01/10
	3 - Educate members and stakeholders - Promote distributed generation where it is economically and technically viable - Develop and implement solar demonstration project.	On-going
	4 Investigate alternative fuel adjustment clause (FAC) formulas that reduce volatility and resolve timing issues.	08/01/10
E) Utilize federal & state funding	E) 1 Request funding from the DOE for smart grid demonstration projects	

Exhibit B

OWEN Electric

A Touchstone Energy Cooperative

2009 Water Heater Program

Owen Electric provides new and current home owners another way to save on their energy bill. Our water heater program provides great savings for members building a new home or replacing a gas water heater. Installing an energy efficient, electric water heater may reduce your utility bill, and possibly give you cash back from the cooperative.

Owen Electric offers a $100 member rebate on qualifying water heaters.

What is a qualifying unit?

The new water heater must meet the following specifications:

- 50-gallon minimum
- GAMA efficiency of .90 or better
- Maximum element size of 5,500 watts
- Proper paperwork-GAMA efficiency rating

Must be installed in a new home or it must replace an existing natural gas or propane water heater.

Fill out form on the reverse side and mail to the address provided.

Program effective Jan. 1, 2009.

Details and terms are subject to change without notice.

OWEN Electric
A Touchstone Energy Cooperative
8205 HWY 127 N P.O. Box 400 Owenton, KY 40380 0-372-7612 fax 502-484-2661

Water Heater Information Sheet

About You

First Name ______________________________ MI ________ Last Name __________________________

Mailing Address ____

City ___________________________ State __________ Zip ______________ Phone _________________

Street Address (location where unit will be installed) ____

City ___________________________ State __________ Zip ______________ Phone _________________

About Your Water Heater

_____ New _____ Replacement Replacing what? ____

Model #: ___________________________________ Serial #: ___________________________________

Element size: _______________________________ Size in gallons: _____________________________

GAMA/Efficiency rating: _______________________________

Manufacturer: ____

About Your Home

\# of Baths: _________________ Sq. Ft. of House: ____________________ Age of Home: _____________

Age and type of heating source: ____

NEW HOME ___________ EXISTING HOME ____________

Signature of member: ____

Date: __________________ Account #: ______________________ Location: _______________________

Please allow 4-6 weeks for processing.

Please mail completed form to:
Owen Electric Cooperative
Attn: Jude Canchola
P.O. Box 400
Owenton, KY 40359

Rebate: $ ________________

Sections "About You" and "About Your Water Heater" are required for all water heater sales.
The entire form should be completed when member is *eligible* for rebate.

OWEN Electric

A Touchstone Energy Cooperative

Touchstone Energy Home
2009 Specifications

Touchstone Energy Home

Insulation

Attic	R-38; Cathedral Ceiling R-30
Exterior Wall	R- 13
Basement Wall	R-10 Continuous; R-13 Framed
Floors	R-19 over unheated space
Slab	R-6
Windows	18% of wall square footage; double pane Low E; less than or equal to 0.35 U-value; if maximum square footage exceeded, see co-op energy advisor for recommendation on increasing exterior wall insulation
Doors	Must be insulated exterior door

Ventilation

Attic	Passive recommended
Crawlspace	Vents recommended
Vapor Barrier	Crawlspace vapor barrier required; 6 mil. poly minimum
Air Infiltration*	House wrap required, seams taped; penetrations caulked; less than or equal to 0.35 natural ac/h, blower door tested; air barrier behind knee walls, fireplaces and tubs. Must be rigid board and must be caulked
HVAC	15 SEER; 8 HSPF; or Geothermal. Load calculation required; ARI certificate required
Ducts	Supplies and return must be insulated to R-6 in unconditioned areas, should be R-4 in conditioned space. Ducts must be sealed with foil tape or mastic
Duct Leakage	Less than or equal to 10% to unconditioned space
Thermostat	Programmable recommended
Water Heater	Electric greater than or equal to 0.90 energy efficiency rating; 40-gallon or greater
Lighting	All can lights must be ICAT rated

The Touchstone Energy Home has the potential for a 30% annual reduction in heating and cooling costs. Owen Electric Cooperative offers rebates starting at $500 for a new home that meets these minimum requirements. Homeowners who choose to install a geothermal heating and cooling system may qualify for an additional $200.

Before you start building your new home, call 502-563-3532 for more information about making your new home an energy saving Touchstone Energy Home. For homeowners to qualify for the rebate program, periodic inspections by cooperative representatives during construction are required to verify compliance to standards.

*The house must be completed before a blower door test can be performed to verify that the house meets the standard.

Rebates subject to change. Certain restrictions apply. Construction must be completed in 2009

Touchstone Energy Living

energy and the power of human connections

OWEN Electric

A Touchstone Energy® Cooperative

2009 Residential Incentives

Owen Electric offers the following incentives to its members to encourage the selection of energy efficient and environmentally-wise residential equipment.These incentives are good for installations made on or after 11/01/2008.

Heating and Cooling Systems

Rebate requests for heating and cooling systems must meet each of the following requirements, plus any additional requirements for that specific type of heating and cooling system.

* Work and installation must be completed in the 2009 calendar year.
* Completed rebate form and copy of invoice or receipt must be submitted to Owen Electric **within 60 days of completed installation.**
* All installations must be in a stick-built home or a manufactured home on a permanent foundation.
* All units must be the initial unit in a newly constructed home or the replacement of a gas (natural or propane) furnace, electric furnace, ceiling cable, or electric baseboard in an existing home.

GEOTHERMAL HEATING AND COOLING - $300

Maximum auxiliary strip heat must be limited to 5 kW. Additional strip heat may be installed, but must be staged for **emergency** use only.

AIR-SOURCE HEAT PUMP- $100

Unit must be 14 SEER (Seasonal Energy Efficiency Rating) or higher and an 8 HSPF (Heating Season Performance Factor) or higher to qualify. (Heat pump to heat pump upgrade is NOT eligible for rebate.) **ARI Certificate MUST accompany rebate form.**

Touchstone Energy® Homes

Rebate requests for Touchstone Energy homes must meet each of the program requirements, plus any additional requirements for that specific type of Touchstone Energy Home.

* Work and installation must be completed in the 2009 calendar year.
* Completed paperwork and copy of invoice or receipt must be submitted to Owen Electric within 60 days of completed installation.

TOUCHSTONE ENERGY MANUFACTURED HOME - $300

- The manufactured home must have the official Energy Star® certification plate affixed to the home indicating that it has been built to program specifications.
- The home must have double-pane windows, added insulation, sealed ductwork, and 14 SEER air-to-air heat pump.

TOUCHSTONE ENERGY STICK-BUILT HOME WITH GEOTHERMAL- $700

TOUCHSTONE ENERGY STICK-BUILT HOME WITH HEAT PUMP- $500

Call or visit your nearest Owen Electric office for requirements before you build.
Periodic inspections are required during construction for rebate.

Owen Electric Cooperative Rebate Request Form

About You

First Name_____________________ MI _________ Last Name ________________________

Street Address____

City ________________________State _______ Zip _________ Phone __________________

Rebate Request (circle one)

Stick-built Geothermal Heat Pump Manufactured _____ New _____ Replacement Replacing

what?__________________________________ Manufacturer:

_________________________ Dealer: ______________________________ Model #

(indoor): _______________________ (outdoor): ____________________________ Serial #

(indoor): _______________________ (outdoor):____________________________ Total

resistance heat (kW): _______________ Unit size (tonage): _______________ SEER rating:

_____________ EER rating: _______________ HSPF rating: ______________

About Your Home

of Baths: ____________ Sq. Ft. of House: ____________ Age of Home: _____________

Age and type of heating source: ____

Age and type of water heater: ____

Signature of member: ____

Date: ______________ Account #: _________________ Location #: __________________

Please mail completed form to:
Owen Electric Cooperative
Attn: Jude Canchola
P.O. Box 400
Owenton, KY 40359

Rebate: $_______

The entire form must be completed within 60 days of installation when member is eligible for rebate. Program effective Nov. 1, 2008. Details and terms are subject to change without notice. Please allow 4-6 weeks for processing.

Exhibit C

Owen Electric Cooperative

2010 Communications Plan

Statement of Mission, Message, and Markets

A key sector of Owen Electric's Customer Service and Marketing Department is Communications. It is the goal of the Communications sector to educate, build trust and loyalty, and increase satisfaction by effectively conveying important Cooperative information to members in a timely and efficient manner.

In delivering this message, Owen Electric wishes to use selected content from a variety of sources including the Kentucky Touchstone Energy Cooperatives marketing schedule, the 2009 Together We Save Campaign, NRECA's Straight Talk campaign, and information and tools catering to member feedback and the climate of our local Cooperative. It is essential that our message and the methods used to convey our message to our targeted markets be consistent with Owen Electric Cooperative's stated values of innovation, integrity, stewardship, commitment to employees, and commitment to community. It is our intent to educate and build positive relationships, trust, and goodwill in our communication efforts.

The markets or audiences we are targeting include our residential members, commercial & industrial accounts, employees, local communities, Greater Northern Kentucky region, county legislators, state legislators, federal legislators, media, Kentucky Public Service Commission, and local community service groups.

Print, internet, radio media, and personal appearances are all venues to be used to communicate and interface with our members, in an effort to utilize as many different forms of media to affect the broadest strata.

Methods

In an effort to reach all members, media, legislators, and regulators, such as the Public Service Commission, Owen Electric utilizes a broad array of media to communicate its messages, including printed media; the Internet; radio advertising; and through local speaking engagements and opportunities.

Print:

Kentucky Living Magazine

Press Releases

Print Advertising

Member Bill Inserts

Drive Thru/Lobby Displays

Internet:

Owen Electric Web Site

Social Networking

-Twitter

-Facebook

Radio:

Seasonal Radio Messages

Big Blue UK Network

Speaking Engagements/Opportunities:

School Groups

Civic Clubs

Community Action Groups

Legislative Opportunities:

Serving on Task Forces

Congressional Meetings—Frankfort, D.C.

Legislative Rally – Washington, D.C.

Public Service Commission:

Informal Hearings

Educational seminars

Rate Case Hearings

Kentucky Living

Owen Electric's member newsletter is sent to all 57,000 members within the *Kentucky Living* magazine.

Frequency: 12 months/year

Content: Follows communications calendar produced by National Rural Electric Association (NRECA); East Kentucky Power Cooperative (EKPC); Kentucky Statewide Assoc.; and relevant Cooperative/industry news as pertinent and timely.

Focus: Coop/Industry news; Climate Legislation; Energy Efficiency; Safety

- Timely or particularly important Cooperative news will take precedent over scheduled communications calendar content.

*Calendars to be incorporated for 2010 upon release

Press Releases

To announce important Cooperative news—including, but not limited to, Outage updates, Capital Credits, Public Service Commission actions or notices—press releases will be utilized.

Frequency: As needed

Audience: Membership or affected sectors according to groups/counties via local media outlets, including newspaper, television and radio.

Content: Pertinent information to be released to public

- Press releases will be distributed through regularly updated e-mail contact lists for the sake of timeliness to appropriate local media.

Print Advertisements

Printed advertisements for newspapers will be approved or denied according to the content/area they include. Discretion will be used in regard to the size and cost of the message in order to ensure all counties and service areas are reached as equally as possible.

Discretion will also be used to determine if the message of the advertisement, as well as any special promotion it might be printed in, furthers the mission and maintains the image of the Cooperative.

Frequency: As needed or as opportunities arise

Audience: Whole membership/regional membership

Focus/Content: School, community support touting 'Commitment to advertisements will include Cooperative '800' number and Web site. Community'; Energy efficiency and education; Safety. All

Member Bill Inserts

Printed bill inserts will appear accompanying mailed Owen Electric member bills on a semi-regular basis to promote new efficiency/education programs or as otherwise needed.

Frequency: Quarterly or as needed

Audience: Entire membership

Focus/Content: Energy efficiency tips, technology/programs that encourage and promote energy efficiency and thus lower utility bills for members

Drive-Thru/Lobby Displays

Printed drive-thru posters and banner-ups for the lobby display matching, colorful promotional messages each month to Headquarters and branch office visitors.

Frequency: Displays year-round; message changes monthly

Audience: Membership, visitors

Focus/Content: Based on Kentucky Touchstone Energy Cooperatives marketing calendar for the current year. Promotes various Cooperative programs, efficiency, CFLs, etc

Web Site

The Owen Electric Web site, while designed to function as a '24/7 Virtual Office,' also features a news scroller section designed to include timely news updates including, but not limited to, outage updates; community/school involvement by the Cooperative and/or employees; and other information of interest.

Frequency: Updated immediately as needed for emergency updates; Updated within 24 hours of community/school/cooperative events, other 'soft' news.

Audience: Membership—especially those with Internet access from home, office, or otherwise (Blackberry, Palm, etc.)

Focus: Outage or safety updates; Energy efficiency and education; Cooperative/community news features; Industry news (i.e. climate legislation).

Social Networking

Social networking is the Communications' sectors most recent endeavor to broaden its reach even further. The sites currently being utilitized—Twitter and Facebook—allow much flexibility in posting articles of interest, video, photos, important Cooperative announcements and updates, and solicit feedback and casual, friendly interaction from members.

Twitter and Facebook also work to reference Web traffic back to the Owen Electric home page, as textual constraints leave the administrator with posting a photo, teaser and link back to the news scroller or appropriate page hosting the article or information.

Twitter

Frequency: Updates as available during an outage; daily, but limited to no more than three (3) updates with articles or energy efficiency tips throughout the day.

Audience: Twitter followers, including members and local media.

Content: Outage updates; energy efficiency and education; Safety.

Facebook

Frequency: Updates as available during an outage; daily, but limited to no more than three (3) updates with articles or energy efficiency tips throughout the day.

Audience: Facebook 'fans,' including local media.

Content: Outage updates; energy efficiency videos, articles and tips; Safety; Community involvement and other 'soft' news.

Radio

Radio advertisements—due to cost—are used sparingly and only when necessary or a reasonable opportunity/sponsorship arises.

Frequency: One to two weeks prior to Annual Membership Meeting according to price of air time and budget constraints; Message during Holiday season two weeks prior to Christmas

Audience: Membership

Content: Information concerning the date, time, and location of the Annual Membership Meeting with features; Holiday message touting non-denominational family-centric safety message.

Speaking Engagements/Opportunities

Invitations to speak to school groups, civic clubs, community action groups, regulators, and/or to participate on task forces and legislative groups will be graciously accepted in order to further Owen Electric's reputation for quality service and its interest in promoting energy education and efficiency. Through its involvement on task forces and in interfacing with regulators, such as the Public Service Commission, efforts will be made to bring awareness to the need for energy innovation, cost of service rates, and climate change public policy that is fair, affordable, and achievable.

Frequency: As opportunities arise and are sought

Audience: Members, youth, community leaders, regulators, legislators

Content: Owen Electric's mission of education in regard to energy innovation, safety, cost of service rates, and fair, affordable, and achievable climate change legislation.

Emergency Communications

Each January, a comprehensive media contact list is updated. This list is used throughout the year to make necessary communications and marketing contact with local newspaper, television and radio media located in Cincinnati, Lexington and Louisville.

Media contacts are notified each year via letter that they can elect to receive emergency outage updates via e-mail. A comprehensive media e-mail list exists much in the fashion of the physical contact list, divided by type of media and including one master list.

Emergency response groups may also elect to become a part of the e-mail distribution list.

Frequency: Immediately as updates/changes develop in the outage/emergency situation; at least every four hours otherwise, between the hours of 6 a.m. and 11 p.m.

Audience: Local media and emergency response groups

Content: Number of members remaining without power; any concrete details pertaining to members and the outage status; safety information in reference to generators, etc; locations of local shelters as the Cooperative is notified.

Key Accounts Communications

Each month all Owen's Key Accounts receive a Questline e-mail newsletter. This newsletter is designed to communicate timely and industry-appropriate information on issues such as energy efficiency, rising costs, government legislation, and best practices. The newsletter is designed to help plant managers, engineers, and financial managers better understand their electric usage and aid in cutting their costs.

Frequency: 12 months/year

Audience: Commercial and Industrial membership

Content: Energy efficiency; Rising costs; Best practices; etc.

MEDIA CONTACTS

Newspapers

CIRCULATION	CONTACT PERSON	FAX	PHONE	E-MAIL	ADDRESS
Lexington Herald Leader	Tom Eblen	859-231-3326	859-231-1415	teblen@herald-leader.com	100 Midland Ave Lexington KY 40508
Courier Journal	Bennie Ivory	502-582-4200	502-582-4691 502-582-4295	bivory@louisvil.gannett.com	500 W. Broadway PO Box 740031 Louisville, KY 40201-7431
Grant County News	Jamie Baker-Nantz, Editor	859-824-5888	859-824-3343	j.bakernantz@fuse.net aperry@grantky.com–ads	151 N Main St, PO Box 247 Williamstown KY 41097
Community Recorders	Susan McHugh	859-283-7285	859-283-0404	smchugh@communitypress.com legalads@enquirer.com–ads	228 Grandview Drive Fort Mitchell, KY 41017
News Democrat	Phyllis Codling, Editor	502-732-0453	502-732-4261	ndeditor@bellsouth.net	PO Box 60 Carrollton KY 41008-1027
Falmouth Outlook	Debbie Dennie, Editor	859-654-4365	859-654-3332	news@falmouthoutlook.com ads@falmouthoutlook.com	PO Box 111 Falmouth, KY 41040
Georgetown News Graphic	Andrea Giusti, Editor	502-863-6296	502-863-1111	news@news-graphic.com classifieds@news-graphic.com ads@news-graphic.com	1481 Cherry Blossom Way Georgetown KY 40324
Gallatin County News	Denny Warnick, Editor	859-567-6397	859-567-5051	galnews@zoomtown.com	PO Box 435 Warsaw KY 41095
News Herald	John Whitlock, Editor	502-484-3221	502-484-3431	jwhitlock@owentonewsherald.com	152 W Bryan St Owenton KY 40359

Radio

STATION	CONTACT PERSON	FAX	PHONE	E-MAIL	ADDRESS
WIOK	Jamie Porter	859-472-2875	859-472-1075	wiok@fuse.net	PO Box 50 Falmouth, KY 41040
WKID	Ken Trimble	812-427-2492	888-959-9543	Mike@959froggy.com	118 W Main St Vevay, IN 47043
WNKR	Jay Anthony TC Sommers	859-824-9835	800-925-1220	wnkrproduction@fuse.net	PO Box 182 Dry Ridge KY 41035
WIKI	Larry Duke	812-265-4536	812-273-2879	wiki_953@yahoo.com	Old Michigan Road Madison IN 47250
WVLK-AM	Robert Lindsey	859-253-5943	877-777-0590	Robert.lindsey@cumulus.com	300 W Vine St Lexington KY 40507
WBUL-FM WLKT-FM WMXL-FM WLAP-AM	Ric Larson		859-422-1000	Contact WLEX-TV	2601 Nicholasville Rd Lexington KY 40503
84 WHAS	Teb Werbin	502-479-2231	502-479-2210	whasnews@clearchannel.com	4000 #1 Radio Dr Louisville KY 40218
55 WKRC/WLW	Jeff Henderson	513-333-4240	513-686-8300	jeffhenderson@clearchannel.com	8044 Montgomery Rd. Suite 650 Cincinnati OH 45236
WGRR	Keith Mitchell	513-241-6689	513-241-9898	keith.mitchell@cumulus.com	895 Central Ave. Suite 900 Cincinnati OH 45202
WKFS	Scott Reinhart	513-749-4925	513-686-8300	scottreinhart@clearchannel.com	8044 Montgomery Rd. Cincinnati OH 45236
WNKU	Craig Copp	859-572-6604	859-572-6500	craig@wnku.org	301 Landrum Academic Center-NKU Highland Heights KY 41099

Television

STATION	CONTACT PERSON	FAX	PHONE	E-MAIL	ADDRESS
WKYT Channel 27	Pope Cudd Assignment Editor	859-293-1578	859-299-2727	pope.cudd@wkyt.com	2851 Winchester Rd Lexington KY 40509
WLEX-TV	Mike Taylor	859-254-2217	859-259-1818	news@lex18.com	PO Box 1457 Lexington KY 40588-1457
WDKY	Pope Cudd	859-293-1578	859-269-5656	newsdepartment@wkyt.com	836 Euclid Ave Lexington KY 40502
WTVQ-TV	Heidi Reihing Assignments Manager	859-293-0539	859-299-3636	news36@wtvq.com	PO Box 5590 Lexington KY 40555-5590
WCPO	Jana Soet Assignments Manager	513-721-7717	513-852-4071	newsdesk@wcpo.com	1720 Gilbert Ave Cincinnati OH 45202
WKRC-TV	Mike Horseley Assignment Manager	513-421-3820	513-763-5421	local12@local12.com	1906 Highland Ave Cincinnati OH 45219
WLWT-TV 5	Matt Bredestege	513-412-6121	513-412-5055		1700 Young St Cincinnati OH 45210
WXIX Fox 19	Mike Ehler	513-421-3022	513-421-1919	mehler@fox19.com	635 W. 7th St Cincinnati OH 45202
WAVE-TV 3	Lee Eldridge News Director	502-561-4105	502-561-4150	aellis@wave3.com	725 S Floyd St Louisville KY 40203
WDRB-TV 41 Fox	Barry Fulmer News Director	502-568-6751	502-561-7711	bfulmer@fox41.com	624 W. Muhammed Ali Blvd. Louisville KY 40203
WHAS-TV	Genie Garner News Director	502-585-5992	502-582-7220	newsroom-all@whas11.com	520 W Chestnut St Louisville KY 40202
WLKY-TV	Michael Neelly News Director	502-896-0725	502-893-7300	newstips@wlky.com	1918 Mellwood Ave Louisville KY 40206

Exhibit D

Project Narrative

The National Rural Electric Cooperative Association (NRECA) is pleased to submit this proposal to support the Department of Energy's (DOE's) Smart Grid Regional Demonstration Program (SGDP) and the Smart Grid Clearinghouse. NRECA, through its research arm, the Cooperative Research Network (CRN), supports 930 co-ops in the adoption of new technology and technology applications meant to control costs and improve reliability and service levels. The project submitted here for your review strongly supports the DOE as it faces the complexity of developing national use cases for speedy, cost-effective deployment of the Smart Grid.

NRECA's proposed project demonstrates diverse Smart Grid technologies, spanning multiple utilities, geographies, climates, and applications. It significantly advances interoperability and security. The content and structure of this narrative is as specified on page 27 of the Funding Opportunity Announcement (FOA). We have included all of the required sections and followed the outline as closely as possible, following a brief introduction to the project, which we deem essential to understanding the narrative. This section includes:

1. Project Objectives
2. The Merit Review / Criteria Discussion
3. Relevance of Outcomes and Impacts
4. Roles of Participants
5. Project Performance Sites
6. Statement of Project Objectives

OVERVIEW OF THE PROJECT

1. *NRECA's CRN has organized a project that will install and study a broad wide range of advanced Smart Grid technologies in a regional demonstration involving 27 cooperatives in 11 states.*
2. *We will install:*
   a. *131,720 smart meter modules*
   b. *18,480 demand response switches*
   c. *3,958 in-home displays/smart thermostats*
   d. *2,825 ZigBee gateways*
   e. *169 voltage sensors*
   f. *247 fault detectors*
3. *The scale of the project offers advantages both in terms of project efficiency and study value. It makes it possible for the co-ops to participate at a higher level than would be possible individually. Planning, procurement, project reporting, high-level engineering, NEPA issues, and the study components are executed by a central team working with the co-ops.*
4. *Installations are planned and executed at the individual co-op level by locally experienced teams.*
5. *Study data will be collected in a coordinated way. Specifications will be developed with the DOE at the outset of the project. The central team will establish a database at NRECA to receive the data, as well as software to validate the data. Working with IT at the co-ops, we will automate collection, validation, and transmission. This system will operate for the duration of the project.*

6. *The data will allow us to conduct the following studies:*

NRECA's Enhanced Demand and Distribution Management Regional Demonstration	
END-TO-END DEMAND MANAGEMENT	***ADVANCED DISTRIBUTION GRID MANAGEMENT***
Advanced Volt/VAr for Total Demand	*Tests of MultiSpeak Integration Extensions*
G&T-wide Demand Response Program over AMI	*Enhanced Use of Integrated Data*
Critical Peak Pricing over AMI	*Multiple AMI Integration at G&T Co-ops*
Water Heater and AC Load Control over AMI	*Distribution Co-op MDM System Applications*
Advanced Water Heater Control and Thermal Storage	*Advanced Volt/VAr for Reduced Losses*
Consumer Internet Energy Usage Portal Pilots	*Self-Healing Feeders for Improved Reliability*
Consumer In-Home Energy Display Pilots	*Meter Data Management Applications and Uses*
Time-Sensitive Rates Pilots	

7. *Installations will be implemented in four successive tranches, each of four months' duration. Each tranche will be treated as a separate project with a firm schedule and deliverables. Data have shown that projects of short duration are much more likely to succeed and that decomposition of large projects is the most effective way to improve performance.*

8. *At the end of each of the first three tranches we will conduct a project improvement exercise, update our Project Management Plan (PMP), and adjust the team and our processes.*

9. *At the conclusion of each tranche, we will conduct a preliminary study. This will help us: (a) improve our study plan and possibly alter the data we collect; (b) assess the type of equipment we are installing and its configuration.*

10. *Results of preliminary studies will be provided to the DOE and disseminated to the co-op community through NRECA's* Tech Surveillance *series. In addition, we will prepare a more qualitative "best practices" report. We believe that early dissemination of results is important—our member community and the broader utility industry are keenly interested in this work.*

11. *Interim and final technical reports provided by NRECA will quantify Smart Grid costs, benefits, and cost-effectiveness; verify Smart Grid technology viability; and validate new Smart Grid business models at a scale that can be readily adapted and replicated around the country. Cost-benefit studies are essential to rapid and cost-effective technology adoption at consumer-owned utilities such as electric cooperatives. They also serve the entire industry well.*

12. *NRECA's mission is to serve its member co-ops. The project includes a comprehensive outreach program using NRECA's full range of capabilities, including reports, seminars, site visits, and Webinars.*

13. *We are taking a comprehensive approach to interoperability. NRECA is the owner and developer of MultiSpeak, the most widely used cross-application interoperability specification in this space. As part of the project, we intend to extend MultiSpeak to address the critical data exchanges between software applications.*

14. *The final MultiSpeak standards will be made available—as consistent with other standards at the end of the project—to the DOE, utilities, and software developers. In addition, we will provide*

any additional source code we develop as a model for future development.

15. *Our approach to cyber security is aggressive and comprehensive. We have engaged Science Applications International Corporation (SAIC) to develop the MultiSpeak security extensions and the integration and data collection software at the co-ops. SAIC has a respected security practice, and two security experts from SAIC are on our team. Its responsibility extends beyond the software to other areas of security such as authentication and perimeter protection. We have also engaged Cigital, which is recognized as the pre-eminent firm in software security. Cigital will provide audit, review and independent validation and verification.*
16. *The project will be completed in four years, during which time we will get the maximum amount of equipment into use and generate useful study results quickly. This project timeline also reduces project labor costs.*
17. *We will continue to collect data using the automated system through five years and make the data available to the DOE.*

1. Project Objectives

The Smart Grid will be comprised of numerous software, hardware, and communications applications operating in harmony. It will never be a packaged product ready for purchase and installation or a straightforward information technology deployment.

Smart deployment of infrastructure on its own, however, will not produce the efficient, responsive grid of tomorrow. The roles and actions of industry and consumer stakeholders must be expanded and understood. Good stewardship of our economic and natural resources demand that we understand the outcomes and costs of these efforts.

The proposed project offers the DOE excellent support as it faces the complexities of developing valuable, relevant national use-cases for speedy, cost-effective deployment of Smart Grid capabilities. Our project involves 27 cooperatives from 11 states, conducts multiple studies, demonstrates a wide range of technologies, expands interoperability, and addresses cyber security. The high-level study structure is outlined below.

NRECA Study 1: End-to-End Demand Management

Study 1.1: Demand Response Using Two-Way Communication
Study 1.2: Utility-Consumer Technology and Pricing Pilots

Core Objectives: End-to-End Demand Management

a. Demonstrate advanced two-way metering infrastructure and conservation voltage reduction programs to study technology readiness and impact on peak demand.
b. Advance systems integration and cyber security controls that will enable end-to-end control and sophisticated pricing signals and load control.
c. Quantify the impact of in-home energy use display devices for household accounts in terms of energy use reduction and shifts in time of energy use; and describe the shifts in customer energy usage behavior in response to the presence of in-home displays and, if applicable, price signals.
d. Support the DOE's SGDP studies, Clearinghouse, and industry/public outreach.

This project will yield rich results not only because it advances and studies key systems and stakeholder actions, but also because NRECA and the electric cooperative network bring unique circumstances, needs, and qualifications to the project, which we describe briefly below.

NRECA Study 2: Advanced Distribution Grid Management

Study 2.1: Integrated Systems Advances and Studies

Study 2.2: Meter Data Management (MDM) Applications and Uses

Study 2.3: Distribution Automation Applications and Studies

Core Objectives: Advanced Distribution Grid Management

a. Develop and test MultiSpeak specification extensions and additional software development to enable and advance systems integration of multiple AMI, MDM systems, self-healing feeders, and advanced Volt/VAr programs.

b. Demonstrate self-healing feeders for low-density utilities and advanced Volt/VAr programs for reducing losses. Learn what works, at what cost—and what doesn't work—and report on case studies and best practices.

c. Measure impact on the power quality and reliability metrics of these programs and report on leading approaches.

d. Support the DOE's SGDP studies, Smart Grid Clearinghouse, and industry/public outreach.

Electric cooperatives have led the utility industry in the adoption of many of the technologies that will form the coming Smart Grid, making the co-ops an excellent laboratory for studying and advancing the Smart Grid. In its August 2006 assessment of the adoption of demand response and advanced metering, the Federal Energy Regulatory Commission (FERC) recognized that market penetration of advanced metering is "highest among rural electric cooperatives at about 13 percent." This compares with 5.7 percent for investor-owned utilities.

DOE Request, FOA P. 6*: to demonstrate how a suite of existing and emerging smart grid technologies can be innovatively applied and integrated to prove technical, operational and business-model feasibility. The ultimate aim is to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve upon the ones that are in common practice today. These demonstration projects should serve as models for other entities to readily adapt and replicate across the country.*

✓ **NRECA Response:** We will conduct two major studies with a total of five study areas. A diverse group of electric co-ops will conduct over a dozen types of demonstration activities. This work will validate technology readiness, enhance interoperability, address cyber security, assess the cost-benefits of and barriers to Smart Grid applications in various configurations, and provide best practices throughout the term of the project.

DOE Request, FOA P. 8 and Appendix Table A.5*: Areas of benefit include: Lower electricity costs, lower demand, reduced costs of power interruptions, lower emissions of greenhouse gases.*

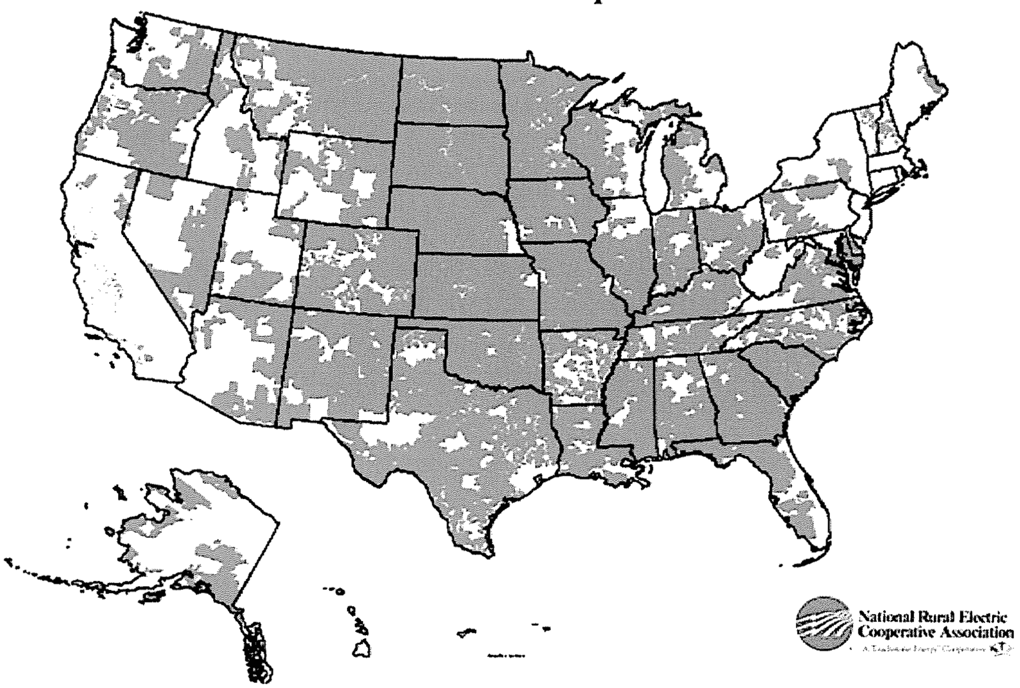
✓ **NRECA Response:** Our project will demonstrate the ability to decrease demand and curb energy use, resulting in reduced energy costs and reduced greenhouse gas (GHG) emissions; improved power quality; and improved system reliability through the use of integrated, secure computerized systems.

NRECA's Electric Cooperatives Network—A Living Laboratory

Necessity drives innovation at electric cooperatives and arises from a unique set of circumstances. As small utilities with limited staffs, electric cooperatives serve vast areas of sparsely populated lands—as well as growing suburban loads. Member-consumers are predominantly residential consumers, farmers, and ranchers; however, high-tech entrepreneurs, big box distribution centers, and sensitive military facilities are also served by co-ops. The overall household incomes of co-op consumers are below the national average.

A total of 930 electric cooperatives serve 42 million people in 47 states (the exceptions are Connecticut, Massachusetts, and Rhode Island). Service territories encompass three-quarters of the U.S. land mass; in terms of U.S. counties, 83 percent are either totally or partially served by electric cooperatives. An emphasis on distribution follows from having 42 percent of the nation's distribution lines to serve only 7 consumers per line mile on average—the electricity industry's lowest consumer density.

America's Electric Cooperative Network

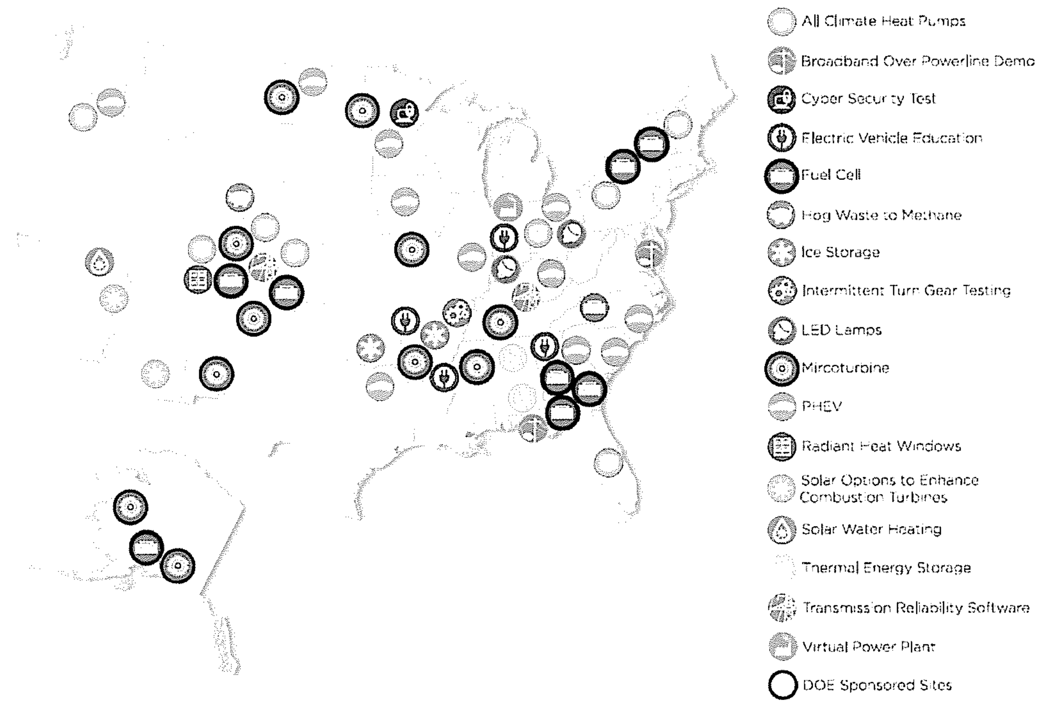


These not-for-profit utilities are consumer-owned and consumer-governed. Co-op boards are elected by the consumers served. Co-op service territories are considered regions in this funding opportunity. Co-op facilities reflect design and construction standards that have been set by Federal agencies, augmented by industry best practices. A co-op in northern Alaska and one in southern Florida, as well as all those in between, have far more in common than any two adjoining investor-owned utilities.

The principal co-op mission boils down to keeping the lights on and the rates as low as possible. Co-ops focus on least-cost planning to achieve reliable service at an affordable cost. Technology plays a crucial role, for it is often seen as the most significant variable under a co-op's control. Technology plans and benefits are communicated across the co-op landscape—from the board room to the co-op staff to the member-consumers. Technology-based solutions are continually being tailored to local conditions at individual co-ops and then shared among other co-ops nationally—a process often described as that of a national "living laboratory."

In the past decade, many utilities saw the benefits of automated meter reading (AMR), but concluded that the economics required tying it into a broader program of distribution automation. Meanwhile, co-ops helped develop a low-bandwidth solution based on power-line carrier. NRECA's CRN—then known as Rural Electric Research—led the effort to commercialize one of the first cost-effective AMR units: the Hunt Technologies "turtle meter" for low consumer-density distribution systems. When two-way AMR – or advanced metering infrastructure (AMI) – emerged, electric cooperatives embraced it.

Demonstration Projects of the NRECA Cooperative Research Network



In another example, the NRECA CRN brought together co-op information technology (IT) staff and vendors of the latest distribution software about 10 years ago to discuss a pressing IT issue. The problem was the high cost and excessive time required to build and maintain interfaces between commercial software packages. Each interface required a customized effort. The solution: the MultiSpeak® voluntary standard, which participating vendors began using to build their interfaces. It has become widely used to speed distribution data transfers and, more recently, has incorporated Internet protocol compatibility, so that Web services can be used to scale MultiSpeak® for large electric utilities. Today, 48 vendors support MultiSpeak®, including Oracle and Siemens, and efforts are underway to harmonize it with the IEC Common Interface Model, the industry's principal alternative.

Finally, the research components of this project are very important to the NRECA CRN. CRN supports electric cooperatives in the adoption, deployment, and application of new technology. One of our principal objectives for the proposal is to learn what works, at what cost, and what doesn't work—and to develop best practices. This NRECA CRN umbrella project will be a highly effective way to validate new Smart Grid business models for electric co-ops and the industry.

Study 1. End-to-End Demand Management

Immense societal challenges call for examining every realistic opportunity to manage demand and to enhance technologies that can deliver electric service more affordably, reliably, and with less environmental impact. Meeting growing demand with little added generation capacity and new environmental requirements warrants significant investment and study. The trajectory of rising costs alone is enough to reconsider resource planning that is dominated by supply-side economics, as has been customary. The ratio of distribution costs to wholesale power costs was once a 40–60 share. Today, that ratio is closer to 20 percent distribution cost to 80 percent wholesale power cost.

But new technologies, such as in-home energy displays, and technology applications, such as critical peak pricing through AMI, offer new tools for sophisticated demand management. Affordability, technology readiness, and long-term effectiveness raise complex questions that need answers before cooperative utilities can make significant investments. Uncovering and communicating best practices in program design and other areas will strengthen and speed deployment.

NRECA's Smart Grid Regional Demonstration will take a leadership role in developing, demonstrating, and collecting data on emerging sophisticated end-to-end demand management applications. Two areas of study will be explored:

END-TO-END Study 1.1: Demand Response Using Two-Way Communications

END-TO-END Study 1.2: Utility-Consumer Technology and Pricing Pilots.

Objective / Study 1.1: Demand Response Using Two-Way Communications

NRECA's member cooperatives are actively developing and operating demand response programs. Nationwide, cooperatives can control approximately 6 percent of their peak load, including approximately 1,440 MW of residential load control. To provide some context, while cooperatives serve about 10 percent of the country's total load, their combined residential demand response resources add up to about 80 percent of the residential demand response capacity of all IOUs put together.

As shown in the table below, this project will develop and test the next generation of two-way demand response (DR) programs. Demonstrations of these new DR systems and approaches will measure the load shifting impact of load control and AMI technology at peak times. These systems and accompanying integration will offer a clear picture of loads before, during, and after events. Unique proprietary AMI products will be linked under a common integration platform.

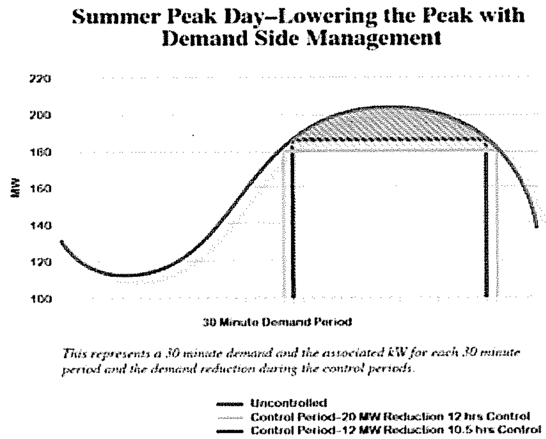
Research Advances and Studies	**Demand Response Using Two-Way Communication**				
Demonstration Activities	Advanced Volt/VAr for Total Demand	G&T-wide Demand Response Program over AMI	Critical Peak Pricing over AMI	Water Heater and AC Load Control over AMI	Advanced Water Heater Control and Thermal Storage
Adams Electric Co-op, IL	○		○	○	
Adams-Columbia Electric Co-op, WI	○				
Clarke Electric Co-op, Inc., IA			○	○	
Consumers Energy, IA				○	
Corn Belt Power Co-op, IA		○		○	
Delaware County Electric Co-op, Inc., NY			○		
Flint EMC, GA			○		

Kauai Island Utility Co-op, HI			○	○	
Menard Electric Co-op, IL	○				
New Hampshire Electric Co-op, NH			○	○	○
Nolin RECC, KY	○		○	○	
Owen Electric Co-op, Inc., KY	○		○	○	
Prairie Power, Inc., IL					
Salt River Electric Co-op Corp., KY					
Snapping Shoals EMC, GA	○		○	○	
United REMC, IN	○		○	○	
Washington-St. Tammany Elec. Co-op, LA	○				

Advanced Volt/VAr to Curb Total Demand. Given the extraordinary amount of co-op-owned distribution line, this project provides an excellent opportunity to develop a series of studies on advanced Volt/VAr control at electric co-ops. Conservation voltage reduction (CVR) programs, a type of voltage control, are capable of reducing peak system demand, which in turn reduces wholesale power costs. Case studies, reports on deployment approaches, and feasibility studies will provide best practices for implementing these advanced controls.

Volt/VAr control is not widely deployed among distribution co-ops except at a rather elementary level where the VAr dispatch and voltage control, if done at all, are done as separate non-integrated systems. Advanced Volt/VAr systems are described here for the purpose of controlling total demand. Such systems are also addressed in Study 2.3, "Distribution Automation Applications and Studies," for the purpose of reducing energy losses.

The proposed Volt/VAr systems are comprised of capacitor banks, voltage regulators, and load tap changer controls. These voltage control and power factor correction devices have two-way communications between the devices and, typically, an integrated SCADA system. Through the advanced SCADA master system, the capacitors and voltage regulators will be monitored and automatically controlled to tweak voltage or toggle capacitor banks on and off. In doing this, the selected feeders and system will establish a flatter voltage profile and closer to unity power factor. These programs may provide a 1.5 percent savings in demand costs.



Integrating Multiple AMI Products to Enable a Single DR System

As distribution cooperatives have embraced AMI, generation and transmission (G&T) co-ops face a growing technology integration barrier. A typical G&T has three- to-five AMI vendors deployed within its service area. Our program will allow a G&T to use the distribution cooperative's two-way AMI system (regardless of vendor) to control load switches as part of a system-wide demand response program.

The objective of this program is to enable a G&T to issue a single command to these dissimilar AMI systems to initiate, terminate, and monitor the status of load control across the system during peak demand. This program solves the existing integration problem and allows G&T co-ops to administer system-wide load control programs over the distribution co-ops' two-way AMI systems.

This "DR manager" will also house the central load management database with all load management subscribers, subscriber groups, and program rules. The system will consist of a front-end communication processor, a database, record formatter, and a report generator to query the database and issue commands. It would not replace load management software within the existing one-way load management (LM) software, but integrate this software's functionality with the two-way LM software suites of leading AMI vendors.

G&T-wide Demand Response over AMI. Addressing the integration problem of multiple AMI systems within a G&T-distribution co-op family will enable a valuable study of an integrated DR system over two-way AMI. (See sidebar, "Integrating Multiple AMI.") This work is extremely valuable as the DOE and utility industry work to make DR a verifiable and dispatchable generation resource. Our project includes deployment of a fully integrated, two-way DR system for an Iowa G&T and its 10 distribution co-ops.

Electric co-ops, as leaders in LM systems, are keenly interested in this work. One obvious benefit to a G&T-wide DR program over two-way AMI is that it will be more effective because switch failure is a known quantity. After 10 to 15 years, LM switch failure rates can exceed 20 percent. If the switch failures can remain low (less than 5 percent), substantial savings will result and the co-ops will be more confident in moving ahead with DR systems.

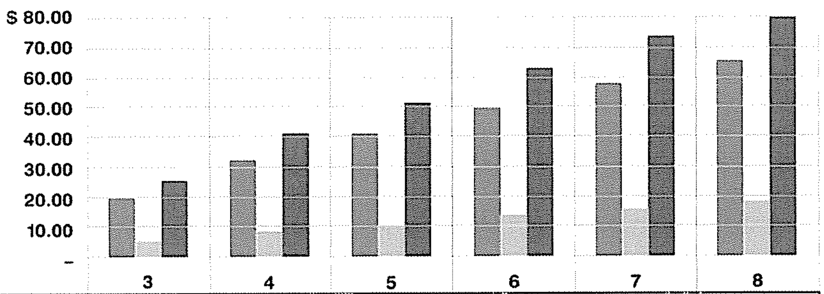
Critical Peak Pricing (CPP) over AMI. Much of what is currently known about critical peak pricing is theoretical or based on a few limited-scope trials. NRECA's project will learn, in pilot programs, what works and what does not work. For example, the project will assess what MW demand reduction can realistically be expected from a CPP event. It will uncover effective practices in program marketing and administration, and the proper notification for the majority of consumers at a typical cooperative. Additionally, the integration of in-home displays (IHD) with an AMI master system for a critical peak pricing program is new, so performance testing is needed.

Water Heater and AC Control over AMI. NRECA's project will explore two-way direct load control of water heaters and/or air conditioning across a dozen diverse markets and climate zones. The improved communications offered by AMI offer excellent opportunities to leverage AMI systems to lower peak demand, derive hourly load shape data, and gain new understanding of the nature and value of direct load control systems. This large sample will provide valuable models for co-ops to follow in adopting this technology.

Advanced Water Heater Control and Thermal Storage. This demonstration activity will test and study the potential of using electric water heaters equipped with sophisticated control technology as distributed thermal storage units. The core conflict in direct load management is that consumers will perceive service degradation (in the form of increased household temperatures or of running out of hot water on demand). Historically, the approach to extending the control period without inconvenience to the end user was to encourage larger units with heavy insulation and high efficiencies. New technologies are superior in providing much more sophisticated control by pre-heating water to 170 degrees ahead of the desired control period. Coupled with cold-water mixing valves, this would substantially extend water heater control periods. If proven effective, this technology could serve to firm up wind generation or be bid into ancillary services markets.

Reduced Market Purchase Costs by Length of Control Period

Annual Savings Per Water Heater
MEC Purchases—Aug 05 – Jul 06



	3	4	5	6	7	8
Weekday	$20.44	$32.40	$40.61	$49.67	$57.79	$65.50
Weekend	$5.05	$8.27	$10.46	$13.11	$15.74	$18.23
Total	$25.49	$40.68	$51.07	$62.78	$73.53	$83.74

Control Period Duration

Weekday Weekend Total

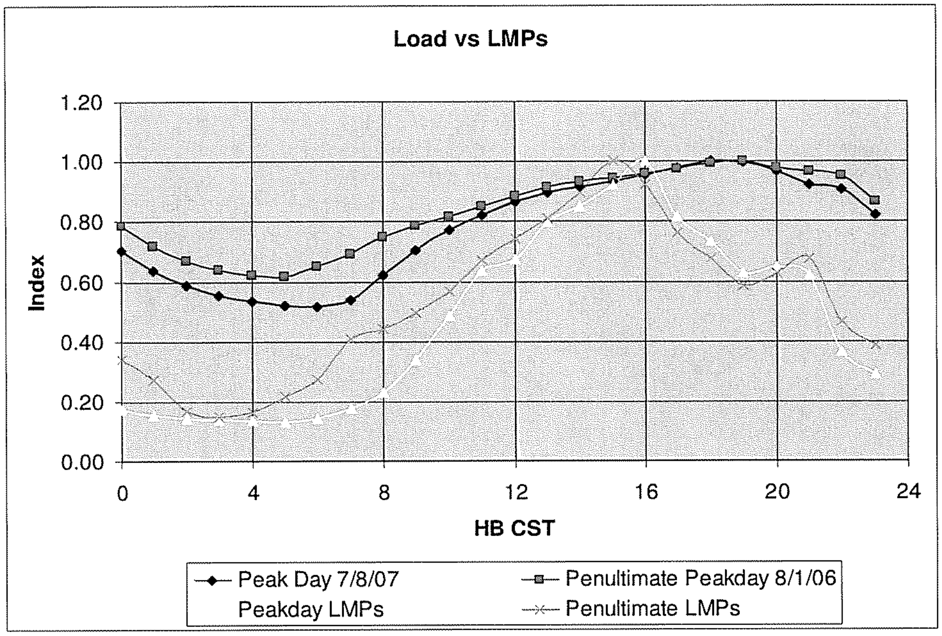
Demonstrations of Demand Response Using Two-Way Communications: Questions to Be Answered

1. How can hourly AMI data for a control group and a test group be used to derive water heater hourly load shapes for 50 and 85 gallon units, which are the most common targets for cooperative load control for a full year? Similarly, how can AMI data be used to derive hourly load shapes for a full cooling season with clear links to hourly weather?
2. How can AMI data for a control group and a test group be used to estimate the impacts during and after control periods of 4, 6, and 8 hours for small and large water heaters and for air conditioners at different ambient temperatures? Is direct load control (DLC) actually energy neutral as is typically assumed?
3. How would load control strategies vary in terms of days and hours of control for peak reduction versus load shifting in hourly market strategies based on simulated control tied to actual historical price, weather, and load data? Which combination of strategies would yield the highest return on investment?
4. What increase in reliability can be achieved by use of two-way load control over older one-way technologies?
5. What business model provides preferred benefit and cost sharing between G&T co-ops and their members in ways that address the most common institutional barriers?
6. Given that AMR investment programs are implemented independently by distribution cooperatives and are

not synchronized with G&T DLC investments, how can synergies be recognized and built into the business case for each stakeholder?

Why Are These Important?

The barrier discussion summarized the primary impediments to significant expansion of DLC among cooperatives. The constraint imposed by flat peak day load curves is illustrated in the figure below which show the correlation and lag between system load and the load management profile (LMP).



The opportunity to exploit market price differentials through frequent (even daily) load shifting is shown by the load management profile (LMP) pattern on this utility's peak day. Substantial incremental gains in DLC value may be possible even when peak reduction potential is limited.

Each of the questions addressed by these demonstration projects is designed to address those barriers. With widespread regional distribution of these demonstration projects, the prohibitive knowledge gaps that impede adoption will be substantially reduced.

Objective / Study 1.2: Utility-Consumer Technology and Pricing Pilots

Reducing consumers' energy use in predictable and significant ways for peak demand and overall energy savings are core objectives for enhanced demand-side management. The project will conduct extensive utility-consumer pilots at a dozen co-ops. As requested on page 8 of the FOA, these projects will provide a baseline set of data and models to enable the DOE to make good estimates of project costs and benefits.

The studies will test in-home energy use displays, Internet energy use portals, and their impact on consumer behavior alone and when combined with dynamic rates such as critical peak pricing and other time-sensitive rates. The focus is on the technological readiness and the economic feasibility of a near-term rural utility mass deployment of this technology.

Research Advances and Studies	Utility-Consumer Technology and Pricing Pilots		
Demonstration Activities →	Consumer Internet Energy Usage Portal Pilots	Consumer In-Home Energy Display Pilots	Time-Sensitive Rates Pilots
Adams Electric Co-op, IL	X	X	X
Adams-Columbia Electric Co-op, WI			
Clarke Electric Co-op, Inc., IA	X	X	X
Consumers Energy, IA	X	X	X
Corn Belt Power Co-op, IA			
Delaware County Electric Co-op, Inc., NY		X	X
Flint EMC, GA	X	X	
Kauai Island Utility Co-op, HI	X	X	X
Menard Electric Co-op, IL	X		
New Hampshire Electric Co-op, NH		X	X
Nolin RECC, KY		X	X
Owen Electric Co-op, Inc., KY		X	X
Prairie Power, Inc., IL			
Salt River Electric Co-op Corp., KY			
Snapping Shoals EMC, GA		X	X
United REMC, IN	X	X	X
Washington-St. Tammany Elec. Co-op, LA			

Consumer In-Home Energy Display Pilots. In-Home Displays (IHDs) promise to reduce overall consumer energy usage and peak demand. Studies have demonstrated that IHDs' effectiveness can range between 0 and 20 percent reduction, depending on how they are implemented. The studies will select representative samples of the population of interest. Participating co-ops will provide data on individual households such as average monthly or annual kWh use over the previous two years, the customer segments that households fall into (for example, which of the 66 Claritas Prizm groups does a particular household fall into), the age and number of occupants, time and hours of occupancy, and income and education.

The demonstration project is intended to observe changes in electric consumption levels and patterns in response to enhanced information delivery and price signals. The information stimuli may differ in terms of delivery technology, information provided, and the frequency with which that information is provided. Technology could be as simple as decorative orbs and simple devices that change colors based on electric system load levels and/or market prices or as complex as in-home displays and smart thermostats that are capable of controlling specific appliances under conditional agreements with host households.

Consumer Internet Energy Usage Portal Pilots. Internet energy use portals (also referred to as Internet dashboards) use the Internet, e-mail, and text messaging as a means of providing usage information and alerts to the consumer. This approach allows consumers to access Web-based information, view usage trend graphs, run queries, and furnish reports to help them understand how they are using energy. Future enhancements to the dashboard products may allow consumers to compare their energy usage with that of their neighbors. This may stimulate some individuals' competitive drive to reduce energy consumption.

If proven effective, these means offer relatively low-cost methods of reducing consumer energy consumption and eliminating IHD hardware and installation costs. Dashboards also can provide features that would otherwise be cost-prohibitive in an IHD device.

But dashboards may have a considerable disadvantage, particularly for some consumer segments. They require consumers to be motivated to visit a Website or to have information "pushed" to their computer or handheld device. And only consumers with the required technology can participate. Hard data and cost-benefit analyses on how consumer segments respond to IHDs and Web portals is critical to developing smart portfolios of technologies and methods to convey price signals to consumers.

Time-Sensitive Rates Pilots. Recent research has shown substantial impact from a wide range of consumer behavior modification strategies. In each alternative, the utility provides time-sensitive pricing information that more closely reflects the wide variation in the costs of electricity by hour, day, and season. Various combinations of reliability, response, and cost are possible. While real-time pricing has long been regarded as appropriate only for large corporate and industrial customers with sophisticated energy management systems, accumulating evidence shows substantial load reduction impacts for residential customers as well. This is particularly important for cooperatives, since a greater share of their load is from residences.

Study 2: Advanced Distribution Grid Management

The automation of distribution systems requires integration and interoperability of a many disparate systems, devices, and software packages. Without this integration, the full capabilities of Smart Grid technologies at the distribution level cannot be achieved. This critical need was clearly recognized by Congress in the Energy Independence and Security Act (EISA) of 2007, when it designated the National Institute of Standards and Technology (NIST) to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems.

DOE's Smart Grid Regional Demonstration will take a leadership role in developing, demonstrating, and collecting data on emerging sophisticated Advanced Distribution Grid Management applications. Three areas of study will be explored in our part of the program:

Study 2.1: Integrated Systems Advances and Studies
Study 2.2: Meter Data Management (MDM) System Applications and Uses
Study 2.3: Distribution Automation Applications and Studies

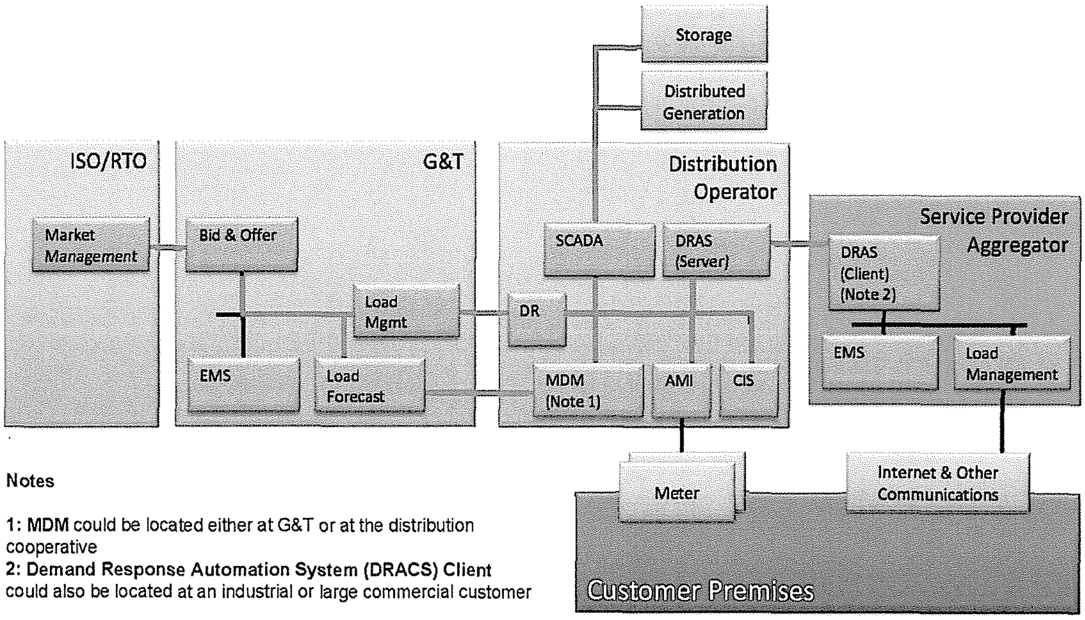
Objective / Study 2.1: Integrated Systems Advances and Studies

For the last decade, NRECA has been working on the MultiSpeak® specification, which is now the most widely used standard in North America (and globally) pertaining to the electric distribution function. Work is underway to harmonize MultiSpeak with the Common Information Model (CIM) for distribution systems (IEC 61968, a standard of the International Electrotechnical Commission). The MultiSpeak Initiative and IEC Technical Committee 57, Working Group 14, are working together to extend IEC 61968 to build MultiSpeak functionality using a profile within CIM, which means that eventually the advantages of MultiSpeak (specificity a reduced need for custom software by utilities—clearly important to smaller utilities with limited staffs) can be combined with other applications that are CIM-compatible. We propose to explore (a) the extension and enhancement of the MultiSpeak specification, including its continued harmonization with the CIM; and (b) the development, implementation, and evaluation of new usage profiles for the integrated data.

Integration Requirements. Although MultiSpeak meets the current needs of distribution utilities, new interfaces will be developed and existing interfaces extended to achieve the goals of the project. We elaborate on the work in two contexts, as it pertains to (a) the end-to-end demand management demonstration and (b) the distribution grid management demonstration.

End-to-End Demand Management. The figure below shows the interfaces that will be required to accomplish the end-to-end demand response demonstration. The potential parties in the demand response transaction are represented by large colored boxes (labeled ISO/RTO, G&T, distribution operator, customer premises, service provider/aggregator, storage, and distributed generation). Smaller boxes within each box representing one of the parties are applications that must exchange data or control signals. Interfaces are shown as lines between applications. Thicker blue lines indicate interfaces that will be developed as part of the project; thinner black lines represent interfaces that do not require development or that will be provided by others. Interfaces to be provided by others include the AMI system to meter interface and all interfaces provided by the third-party service provider/aggregator. The table which follows the figure provides more detail on interface requirements.

End-to-End Demand Response Interface Development Requirements



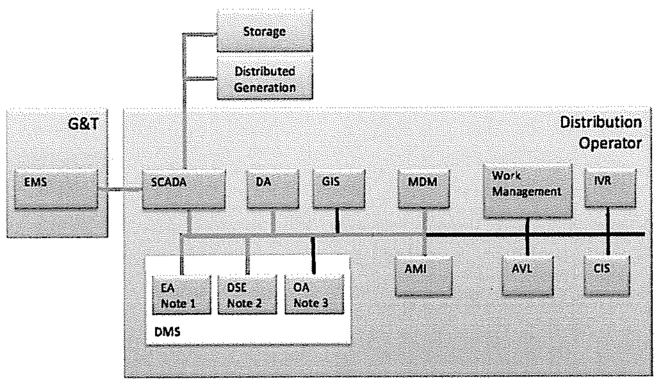
Notes

1: MDM could be located either at G&T or at the distribution cooperative
2: Demand Response Automation System (DRACS) Client could also be located at an industrial or large commercial customer

Required Interface Development for the End-to-End Demand Response Demonstration		
Parties Affected	**Applications**	**Business Requirements**
ISO/RTO, G&T	Market management, bid and offer	This interface implements the market between the ISO/RTO and the G&T, consisting of either capacity price signals or a bid and offer system, depending on the ISO market clearing protocol.
G&T	Bid and offer, load forecast	This interface coordinates the resources available (whether generation or DR) and the price of those resources with the ISO market clearing mechanism.
G&T, Distribution Operator	Load forecast, MDM (Meter data management)	This interface enables the load forecast system to obtain historical metered load information from the MDM system.
G&T	Bid and offer, LM (load management)	Once the load forecast application determines the level of DR resources necessary, the LM application coordinates with the distribution operator(s) on the necessary DR actions.
G&T, Distribution Operator	LM, DR	The LM application issues direct load control, DR signals, and/or price signals to accomplish the required DR actions. The DR system accomplishes the required actions and reports back to the LM system on the amount of DR actually achieved.
Distribution Operator, Distributed Generation (DG), Storage	SCADA, DG EMS, storage EMS	These interfaces enable the advanced SCADA system to communicate with the energy management system (EMS) at the DG and/or storage resources. The SCADA system must be able to obtain status and analog data from the distributed energy resources (DERs). In addition, the SCADA system must be able to pass along control signals or price signals from the DR system at the distribution operator to the DG/storage resources.
Distribution Operator,	DR, CIS, AMI, MDM	These interfaces permit the AMI, CIS, and DR systems to interact so that pricing signals or demand response actions can be transmitted to the customer premise control system via the AMI head end, and feedback on demand actions taken by customers can be returned to the DR and eventually the LM system at the G&T. Furthermore, metered load and meter events must be passed back to the MDM system for subsequent delivery to the load forecast application.
Distribution Operator	DR, DRAS Server	The DR application must be able to pass demand control and/or price signals to the demand response automation system (DRAS) so that it can coordinate DR actions with third-party service providers or industrial customers.
Distribution Operator, Service Provider	DRAS Server, DRAS Client	The DRAS at the distribution operator must be able to send DR actions or pricing signals to the third-party service provider and in return receive demand bids or feedback on customer DR actions that were aggregated by the service provider.

Distribution Grid Management. The next figure shows the interfaces that will be developed in the distribution grid management demonstration. The potential parties in the distribution grid are represented by large colored boxes (labeled G&T, distribution operator, storage, and distributed generation). Smaller boxes within each box representing one of the parties are applications that must exchange data or control signals. Interfaces are shown as lines between applications. Thicker blue lines indicate interfaces that will be developed as part of the project; thinner black lines represent interfaces that do not require development.

Scope of Systems in Distribution Cooperatives and Interface to G&T Co-ops



Notes

1: **Engineering Analysis** (planning. applications, including: topology model. facilities model distribution power flow, optimization of feeder boundaries, and switch and capacitor placement)
2: **Distribution State Estimation** (real time application including: distribution operational analysis, Volt/VAr/Watt control and multilevel feeder reconfiguration) The is not completely covered in MultiSpeak at present.
3: **Outage Management System** (including: fault isolation & restoration. planned outage request and switch orders)

Required Interface Development for the Distribution Grid Management Demonstration		
Parties Affected	**Applications**	**Business Requirements**
G&T, Distribution Operator	EMS, SCADA	The energy management system (EMS) at the G&T must be able to exchange status and analog measurements with the advanced SCADA system at the distribution operator so that each system is aware of the state of the grid operated by the other party. Furthermore, each control system must be able to request the other to take control actions on its behalf in order to relieve power system bottlenecks or to optimize Volt/VAr flow.
Distribution Operator, Distributed Generation (DG), Storage	SCADA, DG EMS, storage EMS	These interfaces enable the SCADA system to communicate with the energy management system (EMS) at the DG and/or storage resources. The SCADA system must be able to obtain status and analog data from the distributed energy resources (DERs). In addition, the SCADA system must be able to take control actions to bring the DER into play where necessary to optimally manage the distribution grid.
Distribution Operator	DMS, SCADA, DA, AMI/MDM	The distribution state estimator (DSE) module of the distribution management system (DMS) gathers information on the state of the system using the SCADA, down-line distribution automation systems, and the AMI (and/or MDM) system. The DSE then calculates the optimal configuration of the distribution system based on current conditions and send control actions to the SCADA and DA systems for implementation.

Tests of MultiSpeak Integration Extensions. The MultiSpeak® specification is a key application-related, industry-wide, open standard for realizing the potential of the Smart Grid. MultiSpeak is the most widely applied de facto standard in North America pertaining to distribution utilities and all portions of vertically integrated utilities except generation and power marketing. It is currently in use in the United States in the daily operations of more than 350 electric cooperatives, investor-owned utilities, municipals, and public power districts. Nearly 50 vendors are actively contributing to and using the specification in developing their standard software product offerings. Over 120 vendor, consulting, and utility personnel have been trained in how to use the specification. The current specification is mature in its coverage of 25 profiles, including meter reading, connect/disconnect, meter data management, outage detection, load management, advanced SCADA, demand response, and distribution automation control—many of the critical aspects of Smart Grid operation.

NRECA's project will greatly further the work with vendors, international standards organizations, and NIST to expand and strengthen MultiSpeak. The specification developed under this project also will be shared openly with the industry at the conclusion of the project. Technology providers are included as advisors on the project team.

Objective / Study 2.2: Meter Data Management (MDM) Applications

Meter data management (MDM) technology is increasingly necessary at electric cooperatives, but the high cost of these systems is a cost barrier. MDM systems range in price from $250,000 to over $1 million. The small cooperative will find a full-blown MDM out of financial reach and will be hard pressed to cost justify even a lower-end MDM. A complete understanding of the benefits of MDM systems (both lower end and upper end) and their value streams is an important area of study. For instance, does an MDM system shared by the distribution utilities of a G&T cooperative make sense? Can a small co-op justify and receive substantial benefits from a smaller MDM that offers fewer applications?

New technical needs driven by the Smart Grid will require support from MDM. For example, firmware libraries will be needed for home area networks and distribution automation. With the immaturity of the home automation products, it is possible that 10 or more types of products with different software and firmware will be deployed in the customer's home within 3 years. Likewise several distribution automation product software vintages will also exist. The MDM will also serve as the library for this purpose and may also be set to complete automatic firmware updates for home automation equipment as new firmware is released.

NRECA's project will study the applications, uses, and comparative value of large, medium and small tiers of MDM systems. Kauai Island Utility Co-op (HI), New Hampshire Electric Cooperative and United REMC (IN) will deploy an MDM as part of their project. In each case, the MDM provides the ability to validate meter readings and filter the data by the electrical location on the system.

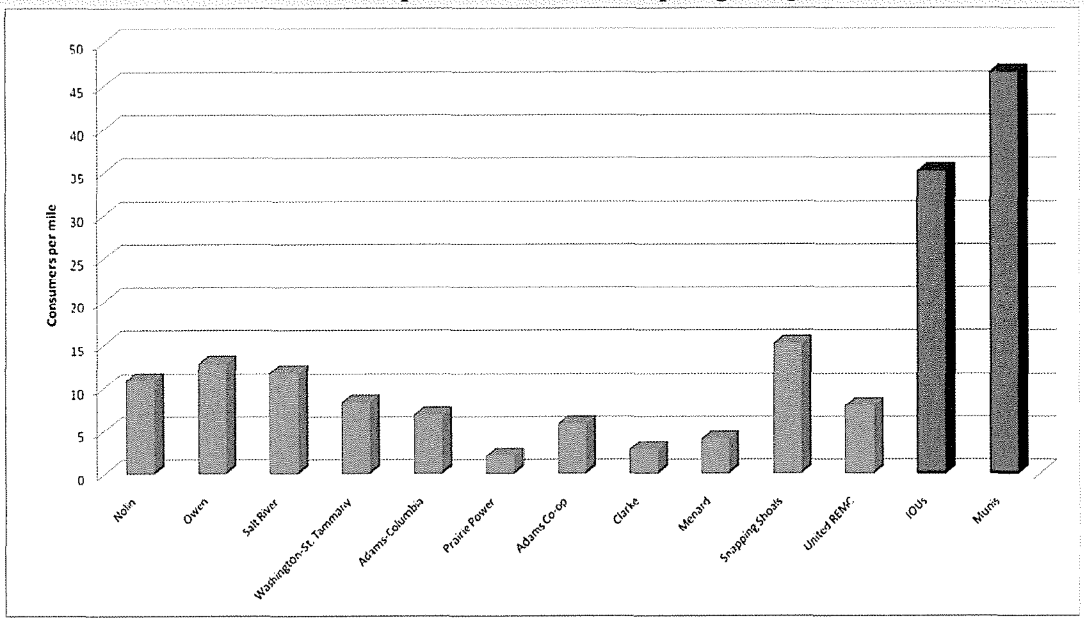
For Kauai Island, the project will use an MDM to accurately balance, in real time, metered customer load with the generation targets set by the automatic generation control (AGC) system. New Hampshire will use it as a repository for pricing schemes and to maintain a database of different kinds of load management consumers. United REMC, a 10,000 consumer-member co-op in rural Indiana, will seek to use a small-scale MDM to validate hourly customer revenue meter readings and to estimate missing readings based on historical data.

NRECA's project will enable the necessary integration of new applications and support the DOE's study efforts, including a careful cost-benefit assessment of the capabilities and feasibility of the different levels of MDM for cooperative families and individual cooperatives.

Objective / Study 2.3: Distribution Automation Applications and Studies

The project will assess the special technical and economic consideration for low-density utilities. Electric cooperatives serve, on average, 7 consumers per mile of distribution line, compared with 35 consumers per mile for investor-owned utilities. The low density and reduced sales per mile of line require that particular attention be paid to the needs of cooperative utilities. They are critical to the national infrastructure, but are fundamentally different from IOUs.

Distribution Automation Applications and Studies: Consumers per Line Mile of Participating Co-ops



The project will investigate the feasibility of widespread deployment, identifying barriers that, if addressed, would enable more low-density utilities to adopt this technology. NRECA's technology transfer plan and capabilities will also raise the visibility of these applications among other cooperative utilities.

Research Advances and Studies	Distribution Automation Applications and Studies		
Demonstration Activities →	Self-Healing Feeders for Improved Reliability	Advanced Volt/VAr for Reduced Losses	Measured Effect on Power Quality and Reliability
Adams Electric Co-op, IL	○	○	○
Adams-Columbia Electric Co-op, WI	○	○	○
Clarke Electric Co-op, Inc., IA	○		○
Consumers Energy, IA			
Corn Belt Power Co-op, IA			
Delaware County Electric Co-op, Inc., NY			
Flint EMC, GA			

Kauai Island Utility Co-op, HI			
Menard Electric Co-op, IL	○	○	○
New Hampshire Electric Co-op, NH			
Nolin RECC, KY	○	○	○
Owen Electric Co-op, Inc., KY	○	○	○
Prairie Power, Inc., IL	○	○	○
Salt River Electric Co-op Corp., KY	○		○
Snapping Shoals EMC, GA	○	○	○
United REMC, IN	○	○	○
Washington-St. Tammany Elec. Co-op, LA	○	○	○

Self-Healing Feeders for Improved Reliability. Much has been made of the Smart Grid's ability to self-heal. Technically known as fault location, isolation, and service restoration (FLISR), this system should produce substantial improvements in the System Average Interruption Duration Index (SAIDI) and other indices.

However, automation technologies to perform these tasks have yet to achieve widespread commercial readiness. While technology tests—such as one undertaken by NETL in partnership with Allegheny Energy in Morgantown, WV—look promising, more work is needed. Few utilities can create a business case that makes sense. Self-healing and even semi-self-healing (which means that action by a human system operator is required) feeders are rare among distribution co-ops. Our demonstration will include a larger geographic footprint and focus on feeders commonly found in rural applications.

Since electric co-ops own about 42 percent of the distribution line miles in the United States, it is important to develop a series of case studies based on actual FLISR implementations at electric co-ops. These studies would help co-ops understand the costs, benefits, and pitfalls associated with implementing FLISR, which could in turn lead to a wider deployment of this group of technologies. Another key result of these case studies could be input to the vendor community on how to improve their offerings to reduce the complexity of system integration and implementation.

NRECA's project will employ a centralized engineering team to work with 11 distribution co-ops to implement various aspects of FLISR technologies. The team would coordinate with the vendors as well as the co-ops to select and implement the technologies in such a way as to gain the maximum amount of experience with the broadest range of rational options.

Advanced Volt/VAr for Reduced Losses. Conservation voltage reduction (CVR) and advanced Volt/VAr programs to reduce total demand were discussed in Objective 1.1, and the same principles are in effect here. CVR is accomplished by reducing the overall feeder voltage still within ANSI voltage standards (without compromising power quality). This can only be accomplished if the distribution lines are properly compensated with power factor correction and/or voltage regulation devices. System efficiencies such as improved power factor are key benefits of CVR programs and merit examination to assess the economics and speed deployment. The project will assess the effect and value of reducing line loading losses and of mitigating power factor penalties from power suppliers. Conservatively, this could be 0.5 percent reduction in losses or greater if there is a power factor penalty.

DOE Request, FOA Appendix, Table A.5: Provide the appropriate reliability data requested by DOE in the FOA Appendix A, Table A.5 to enable it to estimate power quality and reliability benefits in a consistent fashion across DOE's SGDP portfolio. [[Please note that prev. DOE requests in document are in red type.]]

✓ **NRECA Response:** The capabilities that will emerge from NRECA's detailed study of Smart Grid technology applications at multiple utilities across 11 states will create new operations and management tools that will impact the reliability of electric utilities. The electric distribution programs involving smart feeder technologies and included as part of Objective 2.3, will increase reliability indices by: (a) mitigating outages with the introduction of self-healing switching technologies that will sense faults and perform switching routines in concert with other smart-grid networked switches, and (b) making better decisions on restoration efforts based on improved situational awareness achieved in real time.

NRECA will complete a cost-benefit justification of the studies in Objective 2.3, "Distribution Automation Applications and Studies" as it applies to reliability and power quality characteristics and metrics. A clear understanding of the business case for distribution automation deployments is essential for low-density utilities, such as electric cooperatives.

2. The Merit Review Criterion Discussion

Project Approach

Comprehensiveness and completeness of the Statement of Project Objectives (SOPO) that describes the proposed interrelated tasks and of the Project Management Plan that includes a schedule with milestones and explains how the project will be managed to achieve objectives on time and within budget.

The Project Management Plan is presented as a separate attachment. The Statement of Project Objectives (SOPO) is effectively a short summary of that plan. The PMP is comprehensive, detailing the decomposition of the project into about 200 tasks, with a detailed schedule and staff loading. The most important feature of the plan is the decomposition of the project into four successive tranches. Rather than managing the project as a single effort, we have structured it into a series of shorter sub-projects. There is much hard data that the probability of success is much higher in projects of short duration with specific measurable objectives. Any slippage is obvious and must be addressed immediately. There is little time to make up lost ground and remediation cannot be deferred. Short, very well-defined projects provide focus and establish accountability.

Completeness of the proposed demonstration approach to effectively address each of the goals of the applicable program.

We believe that we effectively address the full range of the project objectives—and the top-level objective of accelerating the adoption of Smart Grid technology through:

- The breadth and scale of the equipment we install
- The geographic and operational diversity of our study group
- The multiple study topics (addressed later in this section)
- The comprehensive program for data collection (addressed later in this section)
- The extension of MultiSpeak and the development of end-to-end demand communications
- The provision of the MultiSpeak standard and sample code to advance interoperability
- The engagement of a premier cyber-security team and a comprehensive, full lifecycle approach

Adequacy of the proposed demonstration approach to quantifiably advance program metrics

In the course of the project we will install:

- 131,720 smart meter modules
- 18,480 load management switches
- 3,958 in-home displays/smart thermostats

- 2,825 ZigBee home controllers
- 169 voltage sensors
- 247 fault detectors

These will be installed in 11 states by 27 co-ops that vary in size, operation, and climate. This breadth of activity will provide a compelling demonstration of Smart Grid technologies. The data collected from this volume of equipment and the diverse applications will establish the cost and benefits of the technology. The installation process will help us to develop best practices that will reduce the barriers to adoption of the technology.

Validity of the proposed approach and likelihood of success based on current technology maturity and regulatory/stakeholder acceptance of the technology. Innovativeness of the project, including introduction of new technologies and creative applications of new and state-of-the-practice smart grid.
We believe that we are offering a balanced combination of conservative investment in mature technology and innovation. All of the equipment we are deploying has been deployed commercially. All of the technology, without exception, was under consideration by the participating co-ops before the onset of this project. We are sure that the technology will work.

The innovation comes from our new development work in the extension of MultiSpeak, the development of end-to-end demand communications and distribution management capabilities, and a range of novel applications. Further, we are deploying a wide range of technologies at a very large scale. This is essential if we are to have a real impact on adoption of smart grid technology.

We are absolutely confident that the deployed technology will deliver value and demonstrate it to the broader community and that our development work will advance the state-of-the-art.

Appropriateness and completeness of the demonstration plan including performance objectives of the demonstration, the criteria and requirements used in selecting demonstration site(s), the data collection and evaluation plan, the metrics for success, and the measurements that will be made to confirm success.
As discussed below, we selected performance sites spanning multiple organizations with fundamentally different climates and operating characteristics. Among them are the absolute leaders in Smart Grid adoption. As noted in an earlier part of the narrative, the leading co-ops have been able to move toward greater adoption more quickly than the larger IOUs. Smaller size conveys agility by reducing the size of investment required and streamlining the decision-making process.

The performance objectives are related to projected benefits, summarized in a table later in this section, in criteria addressing the estimated project benefits. The data collection plan is also discussed at length. It relies on a comprehensive data collection system with automated collection, transmission, and validation.

Adequacy and completeness of the project approach in delivering demonstration project data and information to the Smart Grid Information Clearinghouse (where applicable), the Department, and the public.
Automation is necessary to insure reliable and efficient data collection over the course of the project. Accordingly, we will develop the software at each co-op for collecting and packaging data, enable NRECA to receive and store the data, and provide an EDI capability for data transmission. Quality Assurance (QA) routines on each side will insure the completeness and accuracy of the data. Data collection will be developed using MultiSpeak. Data transmission will use FTP.

Data requirements begin early in the project, basically as soon as the study design task begins. The data requirements are driven by study requirements (for example, we collect the data needed for the study) but the study is also driven by the available data (for example, we must build the study based on what data we can practically collect). Working from the results of the design process, we will derive specific data collection requirements and begin a process of developing automated data collection.

The specific data requirements will emerge from the study design, which will be done early in the project, in conjunction with the DOE. We will produce a specific data collection plan, including:

- The data to be collected
- The format of the data
- Units and standard methods for deriving calculated values
- The time interval for reporting
- Methods for addressing interruptions in data flow (marking and possibly imputation of missing values)
- Calibration
- Error detection
- Any other factors necessary to ensure that the data are consistent and accurate

At the outset of the project, NRECA will establish a database to receive all of the data. We will also establish the software necessary to receive the data and, more importantly, to validate it. Non-receipt of data is an obvious problem and is quickly noticed and quickly corrected. A more likely, and more insidious, problem is receipt of incorrect data, unit errors, missing data, misplaced decimals, inaccurate time stamping, etc.

The co-ops will develop systems to collect data in accord with these specifications. In addition, we will specify the method of data collection. This may vary by co-op, and can change over the course of the project as improvements are made to the co-ops' systems. Using a data feed intended to simulate the flow of data from the Smart Grid components, we will test data acquisition in advance of actual installation. We will then test the flow of data through the co-ops' complete systems, integration with other data sources, and packaging for transmission to NRECA. This task is based on the MultiSpeak extensions discussed elsewhere in this narrative.

In addition to the detailed, site-specific information, system information will be collected before, during, and after installation at each co-op. This will include configuration data at the level of major components, with emphasis on changes made during the study period, aggregate systems operation data, weather, significant events like natural disasters, rates and rate structures, and relevant energy market data. This contextual information is essential to understanding system and consumer behavior.

Systems will be developed to collect data from the control group. The data from the control group will necessarily be more limited, since they will lack some of the automated control systems. Beyond site and demographic data, these data will largely consist of hourly load data from central management systems. The control group will provide part of the baseline data. The other baseline data will be data pertaining to the study sites for the period prior to installation of the new equipment

Once the software for data collection (in Tranche 1) is complete, tests will be run to ensure that everything operates as designed. The software and manual processes will be refined as necessary to comply with specifications. Cigital will conduct these compliance tests. After certification, data collection will begin. Automated collection will continue through the end of the project.

Suitability and availability of the proposed project sites to meet the overall program objectives for scope and scale appropriate for the technologies being demonstrated.
As noted previously, we are deploying at multiple locations as listed below. We believe that this set

provides an excellent basis for demonstration and analysis.

Adams Electric Co-op, IL	New Hampshire Electric Co-op, NH
Adams-Columbia Electric Co-op, WI	Nolin RECC, KY
Clarke Electric Co-op, Inc., IA	Owen Electric Co-op, Inc., KY
Consumers Energy, IA	Prairie Power, Inc., IL
Delaware County Electric Co-op, Inc., NY	Salt River Electric Co-op Corp., KY
Flint EMC, GA	Snapping Shoals EMC, GA
Kauai Island Utility Co-op, HI	United REMC, IN
Menard Electric Co-op, IL	Washington-St. Tammany Elec. Co-op, LA
Corn Belt Power Co-op, IA (includes multiple distribution co-ops)	

Adequacy of plans for data collection and analysis of project costs and benefits, including the following aspects:

Thoroughness of the discussion of data requirements (including what types of data and their availability) and how that data will be provided to the DOE so that project costs and benefits can be properly analyzed

The data requirements will be developed during the first task of the project (drafting the Project Management Plan), which includes design of the study. At a minimum it will include the data specified in the FOA. We see the need for immediate extension to collect broader system data as the performance of the technology depends on the context in which it operates. An early deliverable is a document detailing data collection requirements and protocols.

Given the large number of sites where we operate and the number of co-ops involved, we plan to implement an automated data collection system. SAIC, the software lead, will develop a central database, protocols, and software for transfer of data from the co-ops to NRECA, and software to validate the data. This last step is necessary to ensure the accuracy of the submission and to detect problems immediately so that they can be rectified quickly. Power System Engineering and SAIC will assist the co-ops in developing the code necessary to collect the data and transmit it to NRECA.

Logic and completeness of the discussion of how the data can be used by the DOE to develop estimates of project costs and benefits, including the discussion of the Applicant's quantified estimates of project benefits

Two broad categories of load reduction demonstration projects are being proposed that are diverse in size, location, appliance saturations, load characteristics, and demographics. Direct load control of water heaters and central air conditioning systems and various time-sensitive pricing demonstrations will provide a robust repository of measurable load reductions from wide-ranging demonstrations for diverse participants. Peer group experience using well-documented measurement methodologies will reduce or remove major uncertainties that currently retard the spread of Smart Grid technologies within the cooperative community and beyond. Any remaining cooperatives that do not find these results applicable to their systems will have a road map for their own research to fill the gaps in data that drive decisions. The inclusion of both load control and pricing projects will allow the industry to compare and contrast the relative efficacy and cost of these fundamentally different approaches to peak load reduction.

Whether a particular demonstration project involves load control or time-sensitive pricing, the structure of the research that will estimate benefits is similar. The basic research design will require random assignment of customers to control groups and treatment groups and data collection for periods of equal duration in pre-treatment and post-treatment periods. At least 100 consumers should be included for each group, with oversampling to allow for uncontrolled participant defections and for missing data problems that could arise. The population to be sampled for this purpose will be defined by the desired extrapolation of study results. For example, the relevant population might be all residential accounts that include occupied single-family housing units.

This approach will yield changes in average hourly load curves over relevant periods that are attributable to the treatment being tested. Those changes are the critical inputs to benefit estimation. Cost analyses will explore the synergies that exist between AMR investment and direct load control and communication/pricing advances. Separate AMR and load control evaluations understate the net benefits from each.

Comprehensiveness of the plan for determining the baseline against which the costs and benefits will be assessed

The baseline data will be collected for all of the study sites for the period of six months prior to installation. For sites installed after the eighth month of the project, the standard data collection system (described above) will be sufficient. For sites where the install occurs earlier, it will be necessary to derive as much of the data as possible from general system information. This will include factors such as hourly load data.

Another control group will be comparable sites where no equipment is installed. "Comparable" will be defined as similarity in location, use, and structure and on the basis of similar past hourly load profiles.

The degree of the proposed estimates of project benefits

The benefits of the project are summarized by project area.

Activity	Problem Statement	Program Benefit(s)
Advanced Volt/VAr for Total Demand	Lost revenue due to line losses caused by poor system power factor or not having adequate voltage control. Occasionally, voltages are not within acceptable operating limits at feeder ends.	(a) Improve power quality and voltage support, reduce energy losses and system demand. (b) A single integrated system would control appropriate line devices, maintain acceptable feeder voltages, reduce losses
G&T-Wide Demand Response Program over AMI	G&T cooperatives wish to implement a load management program by leveraging the distribution cooperatives' 2-way AMI systems to achieve 2-way communications with load control switches. AMI systems are proprietary and there is no simple integration solution.	(a) This two-way communication allows the G&T to receive an acknowledgment from each switch when issued a command. (b) Gain improved control and command over entire load management system
Critical Peak Pricing over AMI	Critical peak pricing programs have not been technology or performance tested.	(a) Avoid building additional peaking capacity or purchasing costly power during peaks. (b) Reduced retail power costs for members. (c) Energy conservation. (d) Valuable data gained on peak pricing programs.
Water Heater and AC Load Control over AMI	Load management is a proven means of reducing system demand. Traditionally, the load control	(a) Leverage the distribution co-ops' AMI infrastructure for 2-way communications with load control

	systems deployed in the 1980s and 1990s use one-way technology, which has about a 20 percent proven technology failure without a continuous audit program.	switches, thereby allowing the co-op to receive an acknowledgment from each switch issued a command. (b) Avoid building additional peaking capacity or purchasing costly power during peaks.
Advanced Water Heater Control and Thermal Storage	The existing residential heat storage systems are not able to be remotely programmed and operated with a control signal coming from the utility.	(a) Cost avoidance of building additional peaking capacity or purchasing power at very high costs during peaks. (b) Reduced retail power costs for members. (c) Energy conservation. (d) Better use of alternative wind/solar energy as needed.
Consumer Internet Energy Usage Portal Pilots	Studies indicate that consumers who have access to information about their energy usage behavior are more likely to modify behavior by reducing usage. Few consumers have such information.	Allows consumers to access Web-based information, view usage trend graphs, run queries, and furnish reports to help them understand how they are using energy and, in the future, allow remote control of appliances using near-real-time data.
Consumer In-Home Energy Display Pilots	Studies indicate that consumers who have access to information about their energy usage behavior are more likely to modify behavior by reducing usage. Few consumers have such information.	In-Home Energy Display pilots enable consumers to receive information about their energy usage. With this information, consumers may choose to modify energy use behaviors, thereby reducing household consumption and power costs.
Time-Sensitive Rates Pilots	For most consumers, there is little incentive to reduce energy demand during peak times.	(a) Cost avoidance of building additional peaking capacity or purchasing power at very high costs during peaks. (b) Reduced retail power costs for members. (c) Measure the effectiveness of time-sensitive rates.
Tests of MultiSpeak Integration Extensions	Without interoperability, co-ops must choose either expensive custom integration or, by doing nothing, inefficiency and data islanding. MultiSpeak's successful strategy has been used by small and mid-sized utilities' cost-effective data transfers.	Provide the industry with more data on the effectiveness of MultiSpeak as an open specification that defines interoperability between cooperative systems.

Enhanced Use of Integrated Data	The lack of integrated data from systems limits the abilities of utilities to fully leverage the available data in planning, engineering and financial applications.	Use of data for better planning, engineering, or other financial functions.
Multiple AMI Integration at G&T Co-op	G&T cooperatives wish to implement a load management program by leveraging the distribution cooperatives' two-way AMI systems that incorporate load control switches. But AMI systems are proprietary and there is no simple integration solution.	Allow the typical G&T with 10–30 distribution co-op members to administer a G&T-wide demand response program. This requires the G&T to have a single common database working with three to five proprietary AMI vendors.
Distribution Co-op MDM System Applications	Cooperatives are usually too small to fully exploit a full meter data management system. This project will explore uses and value of lower- and higher-end MDM systems for co-ops.	Demonstrate the use of a meter data management system and evaluate cost-benefits for lower- and higher-end systems. Study value at one vertically integrated co-op utility.
Self-Healing Feeders for Improved Reliability	Present systems do not have central intelligence to switch feeders or reroute power automatically. Dispatching crews to manually switch and repair remote feeders reduces reliability and increases costs, and can lead to extended power interruptions.	Smart Grid rapid restoration techniques provide the distribution system with "self-healing" capability in seconds—for example, by rapidly isolating problematic cables, with far less customer dissatisfaction.

Significance and Impact

Significance of the proposed demonstration application versus current practices—Completeness of this assessment to consider benefits in terms of anticipated performance improvements (technical, operational, and environmental aspects) and cost savings of the proposed application over current practices

None of the co-ops involved in this project are installing Smart Grid technologies solely on the basis of the funds available through this program. While the program is an accelerator, the plans for Smart Grid deployment were already underway, strictly on the basis of expected performance improvements and anticipated cost savings.

Degree to which the demonstration project is broadly applicable and adaptable throughout the region or the nation, including the completeness and adequacy of the deployment plan for large-scale deployment in and/or beyond the proposed region

We have explicitly addressed this criterion by designing a project that will operate in 11 states, ranging from New Hampshire to Hawaii. Our participants include small and large co-ops, generation and transmission co-ops, distribution co-ops, utilities with winter peaks and those with fall or summer peaks, as well as co-ops that are both new to Smart Grid technologies and those with some of the deepest penetrations of early Smart Grid technologies like AMI. We believe that the quantitative results of our project, as well as qualitative best practices, will be immediately applicable to our entire membership of 930 electric cooperatives and provide an effective roadmap for adoption of a wide range of Smart Grid technologies.

Adequacy and impact of the public outreach and education plan on public acceptance of Smart Grid transformation

Over its 60-plus year history, NRECA has developed publications, Web sites, training and educational programs that reach the 70,000 employees of electric co-ops, 10,000 co-op elected directors, and over 40 million co-op consumers. NRECA will mobilize its communication tools to disseminate the data and knowledge generated by this demo project. Specifically:

- *First Interim Report.* The first interim report based on the results of the first tranche of installations will take the form of an article in CRN's online magazine, *Tech Surveillance*. It will present an assessment of Smart Grid applications and explore the opportunities and challenges for co-ops, as well as examine the early value proposition for popular devices employed.
- *Second Interim Report.* The second interim report based on the second tranche of installations will also be an article in *Tech Surveillance*. It will help co-ops plan their own Smart Grid deployments using lessons learned from participating co-ops by inclusion of sections on assessing co-op needs, maximizing return on investment, and systematic approaches to deployment.
- *Post-Install Report.* CRN will produce a report summarizing the findings of the demo. This report will explain the entire lifecycle of the demo, give a summary of the data collected, explain how readers can get copies of the full data, and provide any practical knowledge generated over the course of the demo.
- *Quarterly Progress Reports.* To speed dissemination of results to cooperatives, NRECA's CRN will publish concise, quarterly progress reports in its online magazine *Tech Surveillance*. CRN uses *Tech Surveillance* extensively to put technology intelligence and key results in the hands of cooperatives quickly.
- *Seminars.* NRECA will hold more than 22 in-person conferences in 2010. These include its annual meeting (with more than 11,000 attendees); seven regional meetings in which co-ops participate in educational seminars; and the TechAdvantage Conference and Expo, the leading technical meeting for distribution co-op technical staff and mangers. As part of TechAdvantage, a full-day pre-conference workshop on technology planning for the Smart Grid will be incorporated into the meeting. Shorter presentations for the conference itself will look at technical subtopics, such as security, MultiSpeak integrator training, and the potential uses of distribution automation.
- *Forums.* NRECA will conduct annual forums to include project participants, consultants, and industry experts and in years two through four of the project.
- *Webinars.* NRECA will hold more than 75 webinars in 2010. Several could be presented each year on topics related to the regional demonstration. These can be targeted at specific audiences within the co-op community—for instance, CEOs or distribution engineers.

More details on venues and publication channels are provided below.

NRECA Annual Outreach Venues			
Event	Outreach Audience	Audience Size	Tech Transfer
CEO Close-up January	CEOs, general managers, high-level executives	250–300	In-person or video conferencing delivery from expert, industry, and government speakers
Annual Meeting February	National convention attracts co-op board members, high-ranking executives	5,000–7,000 in general session presentations; 2,500 in break-	Video or in-person delivery from expert, industry, and government speakers

		out format	
TechAdvantage Conference & Expo (sister event to annual meeting)	Engineers, operational technicians, IT, purchasing; expo features vendors	500–600	In-person, video conferencing in general sessions and technical breakout sessions
Directors' Conference March	Co-op board members	250–300	In-person, video
Connect Conference April–May	Co-op communicators, member services executives	250–300	Video or video conferencing
New and Emerging Technologies Conference July	Co-op key accounts staff and commercial and industrial customers	250	In-person conference
Director Schools (held in summer/winter in east, west, midwest locations)	Board members	1,400 (aggregate attendance)	Potential for video/print dissemination
Regional Meetings (held in seven meetings between September–November)	Board officers; high-ranking executives	6,200 (aggregate attendance)	In-person delivery in general sessions with opportunities for breakouts
Newsletters delivered through Cooperative.com	Email recipients	Potential audience of about 7,500 on monthly delivery schedules	Web delivery and short articles, referencing cooperative.com resources
Video/Web conferences	Co-op sites	200-300 sites	Delivered ad-hoc as need arises

Principal NRECA Publications
Electric Co-op TODAY, published 45 weeks a year since 1995, covers news for nearly 15,000 subscribers. Over half of subscribers are co-op top managers or elected board members. Thirteen percent are engineering and operations staff. The remaining subscribers (23 percent) have one of the following job functions: communication, finance, human resources, information technology, marketing, consumer-member service, purchasing, and inventory management. Among topics covered in 2009: Climate change, copper theft, energy research, economic development energy affordability, natural disasters, Smart Grid technology, cyber security, mercury emissions, environmental protection, carbon capture, aging infrastructure, and renewable energy.
Tech Surveillance, published six times per year on Cooperative.com, presents articles on research topics covered by CRN and industry updates. *Tech Surveillance* evaluates emerging technologies for their suitability for cooperative applications and features responses to co-op technical questions in its "Ask the Expert" column. *Tech Surveillance* is made available to 9,000 co-op employees.

MQ (Management Quarterly) is a quarterly journal addressing management, board, industry, and organizational issues affecting electric cooperatives. The paid subscriber base of 4,200 consists primarily of directors, CEOs, and senior management. Forty-five percent of subscribers have been receiving the publication for more than a decade.
Perspectives in Brief is published 10 times a year by CRN and delivered to about 1,000 CEOs and senior managers at cooperatives. *Perspectives* provides technology updates and analysis. This electronic newsletter has a high open rate (averaging around 30 percent) and strong reader feedback.
RE Magazine is published monthly and provides in-depth reporting and trends for roughly 30,000 electric co-op directors, chief executives, and front-line employees. Among topics covered in 2009: co-op operations, the latest utility industry technologies, communications, management, safety, and community and economic development.
Straight Talk provides a range of resources supporting electric cooperatives in communicating with their consumer-members. It offers monthly feeds for co-op communicators. All materials—including feature stories, leadership columns, energy efficiency briefs, safety briefs, and technology briefs—may be personalized for use in consumer-oriented publications and Websites. *Straight Talk* content is accessible to all 60,294 subscribers of cooperative.com. Alerts are sent to 1,100 co-op communicators monthly.

Completeness of the proposed commercialization strategy for the technologies being demonstrated
There are two sides to the challenge of commercialization—mature technology that performs and consumer acceptance. We have designed a project that we believe addresses both aspects. Above, we have discussed the value of the demonstrations and our outreach program in making Smart Grid technology visible, demonstrating its efficacy, and providing guidance in the form of our "best practices" reports on how to adopt and apply the technology.

To address the technology side of commercialization, we have included a Vendor Advisory Board (VAB) on our project team. We will work with these advisors through the course of the project to share our on-the-ground experiences. We are also extending the MultiSpeak framework to facilitate direct communication with Smart Grid equipment using open protocols. We will make the standard openly available to technology developers, utilities, and DOE, and provide the source code we develop in the project. We believe that a program of standardization in the communications infrastructure and protocols will simplify and accelerate adoption of the technology. In addition, this common approach will make it possible for companies to integrate components from multiple vendors. The lack of this capability is a major barrier to deployment at the current time.

Extent to which demonstration advances research and demonstration objectives of the program: Area of Interest 1 shall address the goals of the Smart Grid Demonstration Initiative.
The strength of our program in addressing the objective derives from a number of factors:

- The diversity of the technology we are deploying
- The range of geography over which we are operating
- The diversity of the co-ops we are working with
- The range of studies area we are addressing

We addressed the first three of these previously. The table below lists study areas we address in this demonstration. We believe that the breadth of what we are doing will provide a rich body of data and experience to advance understanding of the potential and limitations of Smart Grid technologies.

Demonstration Study Areas
End-to-End Demand Management
Demand Response Using Two-Way Communication
Advanced Volt/VAr for Total Demand
G&T-Wide Demand Response Program Over AMI
Critical Peak Pricing Over AMI
Water Heater & AC Load Control Over AMI
Advanced Water Heater Control & Thermal Storage
Utility-Consumer Technology & Pricing Pilots
Consumer Internet Energy Usage Portal Pilots
Consumer In-Home Energy Display Pilots
Time-Sensitive Rates Pilots
Advanced Distribution Grid Management
Integrated Systems Advances & Studies
Tests of MultiSpeak Integration Extensions
Enhanced Use of Integrated Data
Multiple AMI Integration at Generation & Transmission Co-ops
Meter Data Management (MDM) Applications and Uses
Distribution Automation Applications and Studies
Self Healing Feeders for Improved Reliability
Advanced Volt/VAr for Reduced Losses

Viability and practicality of the proposed technology to meet the needs of the target market in a cost effective manner

As noted above, all technology is commercially available and all of it was under consideration by the co-ops prior to the start of this project. They sought the technology because they were confident that it was appropriate to their needs and practical in its current state. The market is ready for this technology. With the communications and integration protocols and software we will deliver, adoption will become easier and more cost-effective. Through our work with the VAB (discussed in the question regarding commercialization), we believe that the lessons learned in the project will quickly be realized in available products.

Interoperability and Cyber Security

Adequacy and completeness of approach to address interoperability, including the description of the automation component interfaces (devices and systems), how integration is supported to achieve interoperability, and how interoperability concerns will be addressed throughout all phases of the engineering lifecycle, including design, acquisition, implementation, integration, test, deployment, operations, maintenance, and upgrade.

NRECA is the developer and "owner" of the MultiSpeak protocol, the most widely deployed protocol for utility control. NRECA is fully committed to keeping MultiSpeak compliant and consistent with emerging standards at the National Institute of Standards and Technology (NIST) and the Institute of Electrical and Electronics Engineers (IEEE). This will extend to all code and/or specifications developed in the course of this project.

Originated by NRECA, the MultiSpeak® Initiative is a collaboration of leading software providers supplying the utility market, and utilities. The Initiative has developed and continues to expand with a specification that defines standardized interfaces among software applications commonly used by electric utilities. The MultiSpeak specification thus helps vendors and utilities develop interfaces so that software products from different suppliers can interoperate without requiring the development of extensive custom interfaces.

Originally targeted at small electric utilities and covering a limited number of back-office applications, the effort has expanded to where it now offers significant guidance for a range of applications to utilities of all sizes, primarily those that supply electricity, but increasingly for those that supply water and gas services as well.

The MultiSpeak specification defines what data need to be exchanged between software applications in order to support the business processes commonly applied at utilities. In order to accomplish this, it makes use of three components:

- *Definitions of common data semantics.* Data semantics are an agreement about a specific item used in a business process, say a customer or a service outage, which might be exchanged in the context of the outage management business process. Data semantics are documented in the form of an extensible markup language (XML) schema.
- *Definitions of message structure.* Once an agreement has been reached on what data need to be exchanged, it is necessary to define message structures to support the required data interchanges. In MultiSpeak, the XML-formatted data payload is carried as part of a Web services call for real-time exchanges and as part of a batch file for offline transfers.
- *Definition of which messages are required to support specific business process steps.* Web services method calls are linked together to accomplish each potential step in a utility business process. Such steps can then be strung together to support complete business processes.

Real-time MultiSpeak interfaces use Web services to define and implement the data transport. Each Web service consists of one or more methods. MultiSpeak uses Web services description language (WSDL) files to document the methods and define which messages are required to achieve the goals of each method.

Adequacy and completeness of approach for cyber security concerns and protections and how they will be addressed throughout the project, including the adequacy of the discussion of the integration of the new smart grid application into the existing environment, and how any new cyber security vulnerabilities will be mitigated through technology or other measures.

The NRECA team recognizes the importance of cyber security in Smart Grid development. The Smart Grid integrates information systems with utility operations, which opens doors to potential attacks. We must address this issue in the development of the MultiSpeak extensions, the software for end-to-end connectivity, and in the integration of the deployed components into utility operations.

To address this we have engaged a leading software developer (SAIC) and directed that the developer include security specialists on the team. We have also engaged Cigital, the premier software security company in an IV&V (independent validation and verification) and audit function. We address the qualification of the team in a later section and through the individuals' biographies. Here we discuss our approach to security through the software development lifecycle.

Addressing cyber security risk requires a holistic and systematic approach involving cyber security as a key element in all aspects of the project, from planning to requirements specification, architecture, acquisition, design, implementation, integration, testing, deployment, operations, maintenance—all the way through decommissioning. The NRECA team will address cyber security concerns during project planning and kickoff; will incorporate cyber security risk assessment and mitigation activities throughout the development lifecycle of the project; and will develop policies and guidance for cyber security activities to be applied during the full operational, maintenance and decommissioning phases of the delivered system's lifecycle.

From a security perspective, each stage of the development lifecycle comprises the following three elements:

- Security Assessment (Threat Modeling and Controls Selection)
- Security Controls Design/Implementation
- Security Assessment (Security Test and Evaluation)

Further, the following security principles will be considered as security controls and mechanisms are built into the project:

- Holistic (for example, physical, network, software, people)
- Compartmentalization (plan for failure)
- Defense in Depth (security must be multi-layered)
- Secure the Weakest Link
- Protect, Detect, Respond (controls must be multi-faceted)

Security Assessment Methodology
The iterative security assessment methodology to be applied by the NRECA team involves a wide range of activities but is comprised of the following two primary phases:

- Threat Modeling and Control Selection
- Security Test and Evaluation

Threat Modeling and Control Selection considers a system from the point of view of an adversary and the types of attacks to which a skilled attacker may subject a system. During this phase, the goals of an attacker are considered in terms of the system's assets that an attacker may try to compromise. For that purpose, the system's assets and the attack surface (for example, system entry points) are enumerated. Attack patterns are then systematically documented that may enable an attacker to compromise the confidentiality, integrity, or availability of various system assets. In this light, appropriate risk activity rigors and compliance considerations as well as the effectiveness of controls to protect the assets of the system are considered and possible weaknesses are noted. This process is initially used to help identify relevant controls.

Risk-based Controls. Fundamentally, risk-based controls rely on empirical evidence to support the notion that the failure to implement a specific control in the target environment will result in an impact of some likelihood. Such empirical evidence is usually obtained from exhaustive testing and simulation exercises that emulate all possible threats. However, because such exercises are time-consuming and contain an almost limitless set of control variations and permutations, targeted testing is usually deployed to address controls unique to the environment and supplemented by industry best practices and standards, legal and regulatory frameworks, and the expertise and experience of the team members.

Compliance-based Controls. While generally demonstrating significant overlap with risk-based controls, these controls are selected specifically because a law, regulation, or industry standard requires the control to be implemented. In some cases, a deviation may be allowed based on the feasibility of implementing the control and the potential risk of not implementing the control. However, such exceptions are just that. Among the compliance-based controls that will be evaluated against the selected controls in whole or in part include: NERC CIP, NIST SP 800-53, ISO 27001, AMI-SEC, and ISA SP 99. As many of these standards and regulations are still evolving, the NRECA team will continue to monitor their evolution. NRECA team members are currently part of a NIST team that is helping to define cyber security requirements for Smart Grid. Our members are also active participants with AMI-SEC and ISA SP 99 working groups.

Security Test and Evaluation is also an iterative process that verifies the existence and effectiveness of security controls from a risk and compliance perspective. All portions of the process are deployed during the design, implementation, and operational stages of the lifecycle. During each phase the test and evaluation process asks:

- Are the security controls that are being designed or implemented sufficient to protect the system from the attack patterns that have been identified?
- What in the system's design or implementation open up new attack vectors for an adversary? How do we address these?

This process will begin by the development of a test plan that will highlight the tests to be performed, a reference to the expected results, and the logistics for carrying out the test. To help answer the questions above, the testing and evaluation conducted will comprise the following activities in order:

Documentation and Design Review. This activity ensures that policies, procedures, plans, and schematics sufficiently identify all security controls. During the early stages of the development lifecycle, this activity focuses on the initial design and concept of operations and may include facilitated sessions where developers and system integrators offer up proposed designs, including security controls; the assessment team then compares the designs against the controls selected. During later stages, the review ensures that the documentation is complete from both a risk and compliance perspective.

Interviews. The interview activity will largely focus on individuals tasked with performing security-related activities during the operation stage. However, it also inquires as to whether developers are developing code securely and integrators are aware of and deploying the required controls correctly.

Observation and Inspection. This activity generally applies to physical controls in place for the facilities and components of the system proposed. This may include determining whether meters are implementing tamper proofing and tamper alerting mechanisms, whether computer systems are secured in restricted areas, and whether heat and cooling mechanisms are operating appropriately. For the most part, this task can be done after assuming that the environment planned for production does not change.

Configuration and Code Analysis. This exercise examines configuration settings of devices used for the project including meters, collectors, head end systems (user interfaces), and meter data management systems and compares those settings to what the team views as best practices or necessary to meet compliance requirements. For commercial off-the-shelf (COTS) products, it is understood that code review may not be possible. In that case, the team will analyze configuration settings and rely on other technical tests such as vulnerability scans and penetration tests to accomplish the objectives.

Vulnerability Scanning. As part of the testing process, a variety of vulnerability scanning tools will be leveraged to identify potential vulnerabilities in the network and the applications. In many cases, the proprietary nature of Smart Grid components means that standard vulnerability scanning tools will be of limited use. Consequently, the team will draw on penetration testing, configuration analysis, and design reviews to properly identify potential and actual vulnerabilities.

Penetration Testing. Penetration testing performed here uses a combination of manual and automated techniques and is in many respects similar to the pre-deployment penetration tests performed during the development lifecycle. Penetration testing on the Smart Grid will focus on the physical, network, software, as well as people, aspects of security. A combination of technical attacks leveraging information obtained through social engineering techniques are all considered in the work scope. At the end of the day, it is imperative to not underestimate the adversary, taking into consideration a highly skilled, resourceful, and motivated attackers who will use all means at their disposal to attack critical infrastructures of the Smart Grid.

Security Controls Design/Implementation
If the controls selection and assessment process is deployed correctly, the security design and implementation process should be very simple. NRECA will draw upon the guidance provided and include the cyber security professionals in design and implementation, thereby avoiding the common problem of having the cyber security personnel being brought in too late after architectures are set in stone and cannot be changed without significant expense and delay.

Project Team

Completeness and qualifications of the proposed project team, with defined roles and responsibilities for each team member and with appropriate members committed to the demonstration or technology verification
The roles and responsibilities of the project team are discussed in detail in a later section of the narrative. From an organizational perspective, there are clearly defined roles:

NRECA/CRN Project Management (Tom Lovas and Craig Miller) Team Leads (Duane Kexel, Veneicia Lockhart, Sherry Gibson) Administration Procurement Independent Validation and Verification Data Collection / QS DOE reporting Support for DOE study Project Internal Cost / Benefit Analyses Outreach	**Co-ops** Recruitment of study participants Interconnection engineering Installation Integration with utility control system Operation of the technology post-commissioning Primary data collection Imputation of data prior to installation Support for NRECA study activities
SAIC Interoperability, including extensions to MultiSpeak Cyber Security Software development related to data collection Development of database Database collection	**Power Systems Engineering** Assistance to co-ops in technology selection and installation Support for integration activities Lead role on studies, including design Derivation of data requirements Data QA Recruitment of control group
Cornice Engineering Specifications for extensions to MultiSpeak Specifications related to end-to-end operability	**Cigital** Software Security Software IV&V
Pacific Northwest National Laboratories Study design Derivation of data requirements Support for analysis	

Demonstrated level of corporate commitment to the proposed project and proposed cost share as evidenced by letters of intent from all proposed team members.
Letters of intent were included in the Funding Plan.

Demonstrated level of corporate commitment to commercialization of the proposed technology by providing convincing examples of the Applicant's efforts to commercialize the technology in

addition to the proposed project
NRECA and CRN are committed to commercialization of Smart Grid technologies, particularly among electric co-ops, to the fullest extent that they serve our members' needs. Accordingly, we have included three elements in our project plan that specifically address this objective. These are:

- Aggressive and early outreach
- Inclusion of vendors in the project to share in the results
- Development of standards for interoperability that will reduce the cost of adoption

3. Relevance of Outcomes/Impacts

The proposed Smart Grid Regional Demonstrations at electric cooperatives around the country will help define the full meaning of a Smart Grid for the co-op business model nationally. The Smart Grid offers improvements and enhancements to every major segment of the co-op model, from the wholesale market to G&T co-ops (or power supply for co-ops without a G&T) to distribution cooperative to member-consumers. One or more of these segments will benefit from Smart Grid capabilities to decrease demand and energy resulting in lowered energy costs and GHG emissions; improve system reliability through integrated, secure automated systems; and improve power quality, among others.

Enhanced Efficiency, Reliability, and Power Quality—and Cost Savings

The following table estimates the benefits that we expect as a result of deploying the technologies and configurations slated for realizing the program objectives. The table lists the economic, reliability, power quality, and environmental benefits that can be achieved through these demonstration projects. The Program Objectives and Source of Benefits specifically address DOE Appendix, Table A.5, unless otherwise noted.

Summary of Potential Program Benefits				
MW reduction	MWh reduction	Savings—wholesale	GHG reduction, CO2	Reliability increase
1–3%	1.5–2%	2-4%	1.5–2%	5–7%

Economic, Reliability, Power Quality, and Environmental Benefits		
Program Objectives	**Source of Benefit**	**Benefits of NRECA Regional Demonstration**
Reduced electricity cost and peak demand	Flatter load curve as load shifted to off-peak and consumer behavior and smart appliances respond to price signals. Less pressure on electricity rates due to reduced generation costs with flatter load curve	- Load management programs yield 10 kW of load reduction per year per participant - VAr programs reduce energy by 1.5 percent and demand by 0.8 percent - CVR programs give peak demand reduction of 0.8 percent

		- Volt/VAr and SCADA coordination enhance these benefits
Lower T&D losses	Optimized T&D network	Volt/VAr and load management programs lower T&D losses by reducing demand and energy usage and lowering costs
Lower O&M costs	Reduced O&M activity, fewer equipment failures	AMI and automated switching reduce outage "truck rolls." AMI reduces meter reading, disconnect/reconnect, re-reads, and call-center personnel costs
Reduce transmission congestion costs	Increased transmission transfer capability without building additional transmission capacity	Volt and VAr programs reduce demand and energy requirements, which decrease pressure on the transmission system
Interoperability Benefits (FOA, page 42)		
Automate component interfaces	Improved data transfers through the application of an enhanced MultiSpeak	Eleven MultiSpeak interfaces are to be developed, thereby enhancing nine applications
Reliability and Power Quality Benefits		
Lower cost of power interruptions	Reduced number and length of outages	Automatic switching and AMI programs reduce costs of power interruptions, thereby benefiting both co-ops and consumers
Reduce costs due to improved power quality	Reduced number of momentary outages and severe sags and swells, and lowered harmonic distortion	AMI reports voltage levels and power quality at all points of system
Environmental Benefits		
Reduce impacts of global warming	Reduced emissions of greenhouse gases	Demand response, Volt/VAr, and conservation voltage reduction programs reduce demand, in turn reducing power plant emissions. AMI and automated switching reduce vehicle use. CO2/GHG reduction estimate: 1.5-2%
Cyber Security Benefits		
Mitigation of new cyber security vulnerabilities, FOA page 42	Cyber security risk assessment and mitigation activities incorporated throughout the development lifecycle of the project, including decommissioning	Cyber security standards are applied at both the technology level and the management and operations level (for those technologies). Also, hardware and software are tested fully, as are installed systems to determine the effectiveness of cyber security measures.

We will now take a closer look at outcomes and impacts of a number of demonstration objectives that expand upon the above:

Load Management. The benefits due to load management may be categorized as either "demand savings" or "energy savings." Demand savings occur when a utility purchases energy from another entity, such as a distribution cooperative purchasing power from a G&T, and the load management system reduces the billing demand in kW for a given month. The distribution cooperative would realize immediate savings in demand charges. However, savings by the G&T could be realized only when it could avoid or delay the cost of new generation.

Energy savings involve one or more of the following: (a) avoided energy charges, as determined by the tariff implemented; (b) avoided generation costs for the power supplier; (c) avoided energy purchase costs for an entity exposed to hourly energy markets.

Load management entails the installation of load control switches typically on water heaters, irrigators, and air conditioners. For these loads:

- Control of an air conditioner reduces system demand by 0.9 to 1.1 kW.
- Utilities without access to natural gas for water heating may instead offer controlled or stored electric water heating and achieve reductions per 0.8 kW per user for each consumer.
- Irrigation load control depends on installation size and the specifics of the application—for example, soil type, weather pattern, and crop. Controlled loads range from 10 to 30 kW per installation and the total system impact depends on the utility's total number of installations. One cooperative with 6,000 irrigation pump installations in a load management program can shed 80 MW during peak periods.

The amount of load-management savings depend directly on the number of participants. As an example, assume a utility has 100,000 members and 50 percent have electric water heaters. Of those, 50 percent participate, for a total program size of 25,000 participants. At a monthly savings of 0.8 kW per installation, the utility would realize 20 MW of reduced load each month. Further, if the wholesale rate is $15 / kW per month, the annual demand savings translates to $3.6 million.

One-Way versus Two-Way AMI. Two-way metering makes a major difference. Two-way metering enables a utility to identify failed modules and then replace them, for an overall reduction in failure rates. The following table illustrates that the demand savings are significantly higher as a result. A reduced level of failures—1 percent versus 20 percent—translates into the greater net savings of $684,000 annually.

Annual Net Savings for 100,000-Member Co-op using Two-Way AMI: $684,000			
	Do Nothing	**15-Year Old One-Way System**	**15-Year Old PLC Two-Way System**
Total Members	100,000	100,000	100,000
Total Number of Water Heaters (@ 50%)	50,000	50,000	50,000
No. of Participants (50% LM Penetration)	0	25,000	25,000
Failed Units %	0%	20%	1%
Number Participants Controlled	0	20,000	24,750
Yearly Demand Savings at $15 / kW Month and 0.8 kW Demand Reduction per Water Heater Participant	**$0**	**$2,880,000**	**$3,564,000**

Conservation Voltage Reduction (CVR). Implementing a CVR program requires the installation of programmable regulator controls that can interface with advanced SCADA. Typically, one can assume that a 1-Volt reduction in voltage, for a 120-V line, yields 0.8 percent peak demand reduction and keeps the distribution voltage profile within regulatory limits. Again using typical numbers, let's say that a 4 percent voltage reduction will yield a 3.2 percent demand reduction in an annual demand bill of $12.5 million. The annual savings total $400,000.

VAr Control. Implementing a VAr control program requires the installation of capacitors and programmable controls, and potentially communication links back to SCADA. The benefits depend on system specifics—for example, loads, type of line construction, and power factor—to determine the actual demand reduction and energy saved. For example, let's assume a net savings of 1.5 percent in energy, 0.8 percent in savings and no VAr penalty. The actual energy saved for a 4,500,000 MWh system load at 1.5 percent loss reduction at $40/MWh is $2.7 million. The annual demand savings for a $12.5 million demand bill at 0.8 percent is $100,000.

Coordinated CVR and Load Control Using Advanced SCADA. The key to maximizing demand reduction throughout a system is to combine AMI, LM switches, and CVR with a SCADA software solution that is developed to coordinate system-wide control. The software uses an algorithm to perform the following functions:

- Direct the CVR to lower control voltage while maintaining standard regulation limits.
- Automatically disconnect non-essential residential switches, such as hot water heaters or air conditioners through AMI, and predetermined C&I loads (through prearranged agreements) to maintain system balance when the load demand exceeds supply.

This coordinated control system can further reduce demand by 0.5 percent.

Coordinated Volt/VAr. Finally, still further improvements can be achieved from a coordinated Volt/VAr program based on innovative techniques now becoming available. Seeking to improve regulator and capacitor control coordination, the manufacturer Beckwith Electric states that, if properly implemented, an additional 1–3 percent in energy savings and 2–3.5 percent in demand savings can be obtained using an adaptive Volt/VAr management system. A comprehensive system design, including the elements discussed above, is recommended to maximize Smart Grid benefits for a coordinated Volt/VAr program.

MultiSpeak Integration. MultiSpeak integration brings together information and functionality from multiple software applications. Often, the results are presented to the key employee in a single user interface to make the appropriate choice of action clear. Such integration makes it possible for utility employees to efficiently monitor the information necessary to make appropriate and timely decisions and take effective action, often while remaining in a single software application.

The combination of AMI and SCADA systems interfaced with an Outage Management System (OMS) illustrates how the integration of Smart Grid applications can result in better operations decision-making. The outage detection functionality of the AMI system, along with real-time access to SCADA device status, can permit the system operator to dispatch crews directly to the site of the outage. Once the crew completes its work, the operator can ensure that restoration is complete by checking the outage status of AMI-enabled meters before the crews are released to work other outages, thus eliminating the need to re-dispatch a crew to fix outstanding, single-customer outages in the area. This capability alone has proven to save nearly $5 per consumer per year in one case study (Doug Lambert, Robert Saint, and Gary A. McNaughton, "Implementation Experience with NRECA's MultiSpeak® Integration Specification," *Proceedings of the 2007 Rural Electric Power Conference,* New York, NY: Institute of Electrical and Electronics Engineers, Inc., 2007).

Had the standardized interfaces inherent in MultiSpeak not been available, the utility in question would have had to spend approximately $100,000 in custom programming (approximately $4/consumer) to obtain the same benefits and typically would have to spend about $15,000 per year for maintenance on those interfaces (about $0.60/consumer/year) and $50,000/year in staff costs (about ½ full-time equivalent IT staff member—fully burdened, at a cost of about $2/consumer/year) to maintain the customized system. This is one example of the value of MultiSpeak integrated systems: The critical need for interoperability has been recognized by DOE in this funding opportunity

Enhanced decision-making through integrated systems requires not only achieving integration but also determining what to do with all the data once they are available through the integration of multiple systems. This is very much like the produce on the shelves of a supermarket. Integration puts all of the different ingredients on the shelves, but recipes are needed to turn the ingredients into tasty dishes. These recipes are particularly important to smaller utilities such as co-ops, which often don't have staff time to do creative data mining. They will also be of special value to vendors seeking new applications and algorithms to productize. The expansion of MultiSpeak proposed in this project will address many significant issues associated with new integration needs for the Smart Grid, as well as simplify technology implementations and system maintenance.

4. Roles of Participants

The National Rural Electric Cooperative Association (NRECA) and its supporting electric cooperatives are uniquely qualified to execute the proposed Smart Grid Regional Demonstration Project and communicate its findings to speed economical deployment of the Smart Grid. Both the need and the skills are embodied in this group.

NRECA is the gateway to over 900 electric cooperatives which provide power in 47 states serving 42 million consumers, or 12 percent of the U.S. population. Engaging NRECA and the electric cooperatives is vital to the success of the DOE's Smart Grid initiatives.

There can be no Smart Grid without addressing the special challenges and needs of electric cooperatives. There are two key reasons for this assertion: (a) Cooperatives own and operate four of every ten miles of distribution line in the United States, and (b) They cover roughly 75 percent of the land area of the country, providing electric service in 83 percent of U.S. counties.

In addition, NRECA electric co-op members:

- Own assets worth $112 billion (distribution and G&T co-ops combined)
- Own and maintain 2.5 million miles, or 42 percent, of the nation's electric distribution lines, covering three-quarters of the nation's landmass
- Deliver 10 percent of the total kilowatt hours sold in the United States each year
- Generate nearly 5 percent of the total electricity produced in the United States each year
- Employ 70,000 people in the United States

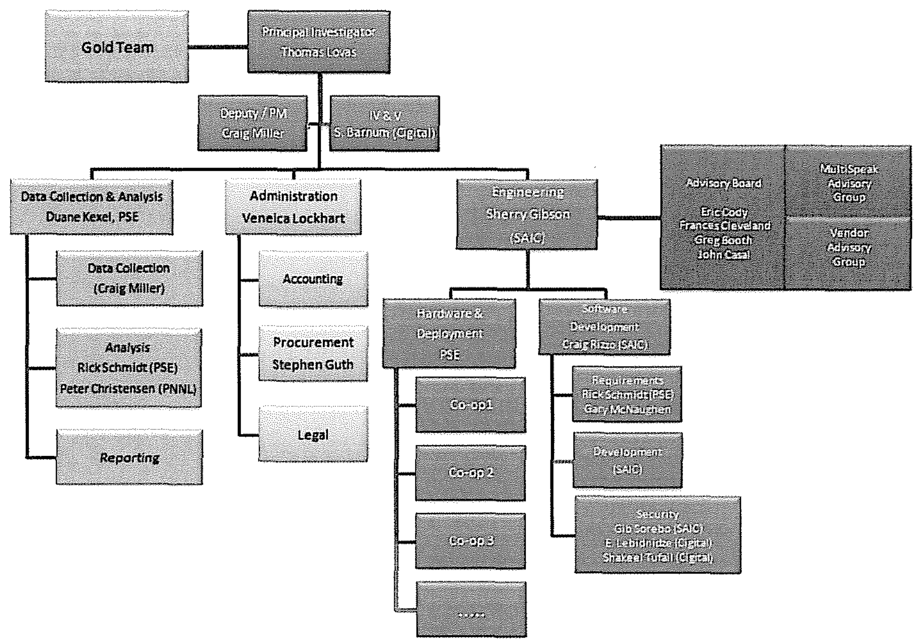
America's electric cooperative network is already poised for adoption of Smart Grid technologies due to its previous work in this area, its flexibility, and its ability to make rapid management decisions. Because of the large number of co-ops taking part in this demonstration, and the variety of work involved, NRECA assembled a diverse and flexible project management structure. It is divided into three principal teams:

- Management Team (Red)
- Engineering Team (Blue)
- Administrative Team (Green)
- Data Collection and Analysis Team (Brown)
- Advisory Groups (Purple)
- Management Advisory Group (Gold)

The teams operate under the direction of a Management Team (Red) and with the support of a Management Advisory Group (Gold). In addition, NRECA will seek the involvement of a wide range of industry experts: an Engineering Team, a MultiSpeak Initiative Advisory Board, and a Vendor Advisory Group. Finally, the project teams will work closely with the full range of co-ops and with the MultiSpeak vendors to ensure that all work meets interoperability standard for the industry.

The function of each team is described in the following sections. After introducing the teams, we discuss the participating organizations.

Smart Grid Regional Demonstration Organization Chart



Engineering Team (Blue)

The Engineering Team will work on the specification, interface, and integration of Smart Grid components, serving as high-level advisors and consultants to the co-op engineers who will install these components. The basic systems for data collection will be implemented by this team, though specifications of the data to be collected will come from the data collection and analysis team. Cyber security is also a major team responsibility. The Engineering Team consists of:

SAIC

SAIC is a leading provider of scientific, engineering, systems integration, and technical services and solutions. Since its founding in 1969, SAIC has grown from a small group of highly specialized domain experts to a FORTUNE 500 company with more than 45,000 talented professionals worldwide. It now serves customers in the U.S. Department of Defense, the intelligence community, the U.S. Department of Homeland Security, and other U.S. Government civil agencies, as well as selected commercial markets including the oil and gas industry, utilities, and pharmaceutical companies. SAIC plays an influential role in important national and global programs, such as defense modernization, border security, intelligence analysis, global climate change, and cancer research.

- Sherry Gibson, SAIC (Vice President, Energy Solutions Operations)
- Craig Rizzo, SAIC (Smart Grid Services Practice Lead)
- Gib Sorebo, SAIC (Chief Security Officer)

Cornice Engineering

Cornice Engineering, Inc. provides engineering consulting services to meet the rapidly changing needs of the electric power industry. Cornice specializes in assisting utilities and research organizations to implement and integrate automation and information systems with emphasis on choosing appropriate technological solutions. The principals of Cornice have worked directly with nearly 20 utility clients as well as provided contract research for organizations such as the National Rural Electric Cooperative Association, the Electric Power Research Institute, the Jet Propulsion Laboratory and NASA. Cornice's contract research engagements have led to the development of core competencies in modern software design techniques such as business requirements analysis, UML modeling, XML Schema development, and Web services design.

- Gary McNaughton, Cornice Engineering (Vice President)

Power System Engineering

PSE is a full-service consulting firm for electric utilities. The professionals at PSE include engineers, IT and integration experts, utility automation and communications experts, economists, and rate and financial analysts with extensive experience in all facets of the utility industry. PSE services include communication design, procurement and project management, distribution & transmission system design, rates and financial planning, substation automation, and many others. PSE assists utilities with managing their technology projects from procurement to implementation, and is currently involved in planning, procurement and implementation projects covering next generation SCADA systems, distribution automation, GIS, AMI, critical peak pricing (CPP), substation automation, communications design, and deployment, to name a few.

- Duane Kexel, Power Systems Engineering (Executive Consultant)
- Rick Schmidt, Power Systems Engineering (Vice President, Utility Communication Systems)

Cigital

For 17 years Cigital has been an industry leader in the development of techniques for software security best practices. Cigital's approach to software security has its foundation in a technical methodology entitled "Building Security In," which is a holistic approach to integrating software security best practices throughout the SDLC. Clients include the Department of Homeland Security, the National Security Agency, Bank of America, Fidelity, Marriott, Intuit, VMWare, Federal Reserve Bank, Qualcomm, Electronic Arts, U.S. Air Force, and over 200 others. Cigital employees are experts in their field:

- Sean Barnum, Cigital (Principal Consultant)
- Shakeel Tufail, Cigital (Managing Consultant)
- Evgeny Lebanidze, Cigital (Senior Security Consultant)

Pacific Northwest National Laboratory

PNNL is one of the DOE's 10 national laboratories, managed by the DOE's Office of Science. PNNL also performs research for other DOE offices as well as government agencies, universities, and industry to deliver breakthrough science and technology to meet today's key national needs. PNNL provides the facilities, unique scientific equipment, and world-renowned scientists/engineers to strengthen U.S. scientific foundations for fundamental research and innovation; PNNL prevents and counters acts of terrorism through applied research in information analysis, cyber security, and the non-proliferation of weapons of mass destruction; PNNL increases U.S. energy capacity and reduces dependence on imported oil through research of hydrogen and biomass-based fuels; PNNL reduces the effects of energy generation and use on the environment.

- Peter Christensen, Pacific Northwest National Laboratory

Administrative Team (Green)

The Administrative Team has responsibility for overseeing financing, procurement, and contracts for the project. This team also addresses any legal issues arising from the project. Given the scale and importance of the project, we have tapped Veneicia Lockhart, NRECA's Vice President of Finance, to lead the Green Team. She has extensive experience in the administration of Federal contracts, with DOE and other organizations, most notably NRECA's very successful international energy development projects. Her position within NRECA gives her access to all of the organization's financial management capabilities.

The project is a complex one with extensive site-related work, permitting, and procurement. The Smart Grid hardware alone will account for $35 million. Procurement of items in this class is not a simple matter of ordering. Issues such as transport, insurance in transport, consequences of delay, timing of the transfer of title, start of warranty, remediation of defects, etc., that must be worked out. For this reason we have included on the team Stephen Guth, who is NRECA's Vice President of Vender Management and Legal Services and a senior procurement specialist. Mr. Guth has professional certifications in project management and purchasing management, and has authored books on vendor management and contract negotiation.

- Veneicia Lockhart, NRECA (Vice President of Finance)
- Stephen Guth, NRECA (Vice President of Vender Management and Legal Services)

Data Collection and Analysis Team (Brown)

The Data Collection and Analysis Team will coordinate with the Department of Energy in the design of the data reporting requirements and of NRECA's responsibilities of analysis. This work will be done as early in the project as possible in order to focus the data collection effort and get it underway early. We plan to make an up-front investment in the development of automated data systems. We will establish a database at NRECA to receive all of the data and a capability for electronic data interchange, incorporating algorithms for flagging anomalous or erroneous data at the time of collection so that these can be corrected quickly. Once this is in place, data collection will be largely automatic, reducing cost and increasing reliability. Craig Miller has been designated to lead this effort on the basis of his IT experience, particularly with electronic data collection. Dr. Miller pioneered early EDI systems for the Energy Information Administration and developed the system currently used by the Environmental Protection Agency to collect emissions data for the Acid Rain Program.

The second function of the Data Collection and Analysis Team is to support the DOE as required in execution of its cost-benefit studies and to conduct the internal research program. To that end, we have engaged Dr. Duane Kexel of PSE and Dr. Peter Christensen of PNNL to lead the economic analysis.

Management Team (Red)

The Management Team provides executive leadership, high-level decision making, and industry insights to this demonstration. This requires a deep understanding of both the utility industry (provided by the principal investigator) and the process of executing a government grant (provided by the deputy/project manager).

The Principal Investigator (PI) is Tom Lovas. He is the overall leader of the project. He was chosen for this on the basis of his deep experience in the utility industry, extensive experience managing research projects, and experience building alliances across utilities and related corporations, schools, and laboratories. The PI has ultimate responsibility for execution of the project. The PI will:

- Be the principal point of contact with the Department of Energy, interfacing with the Contracting Officer (CO).
- Officially submit all project reports, though these will largely be prepared by the Project Manager (PM) supported by the heads of the three principal teams: Data Collection and Analysis, Administration and Finance, and Engineering.
- Initiate and/or present any changes in the scope or execution of the project for its duration.
- Prepare and deliver the project summaries for mid-project progress meetings.
- Play a major role in development of the Project Plan (Task 102 (Task 1 of the FOA)), present it to DOE, and resolve any conflicts.
- Monitor the activities of the three project teams (Data Collection and Analysis, Administrative, and Engineering), help to identify problems either within or external to the team, and resolve problems.
- Provide quality assurance of all technical work.
- Advise and meet with the Management Review Team.
- Participate in preparation and/or review of technical reports.
- Conduct outreach to key audiences and disseminate results.

Principal Investigator: Tom Lovas, Energy and Resource Economics (Principal Consultant), has more than 30 years in the utilities industry, including extensive experience managing research projects as well as building alliances across utilities and related corporations, schools, and laboratories. He currently provides program coordination for NRECA in the areas of generation, transmission, and strategic alliance.

Project Manager: Craig Miller holds a Ph.D. in systems engineering from the University of Virginia. He is a frequent lecturer and speaker in the areas of software quality, application integration, information security, advanced IT architecture, and distributed information and energy technology. As Project Manager, Dr. Miller will manage operation on a day-to-day basis, providing support to the Principal Investigator. While Dr. Miller's background is in energy systems engineering, he is engaged here as a complement to Mr. Lovas due to his experience in management of government contracts dating to 1976. He will support Mr. Lovas while working daily with the Data Collection and Analysis Team and with the Administrative and Engineering teams.

Management and Engineering Advisory Team (Gold Team)

To provide insight into the utility industry and, in particular, into the needs of electric co-ops and their customers, NRECA selected Management and Engineering Advisory Team members from within its own management structure. They are involved to provide advice and counsel to Principal Investigator and to provide a final check on NRECA's performance. Collectively, this team has more than 100 years of experience in the electrical utility industry. The Gold Team members are:

- Martin Lowery, NRECA (Executive Vice President of External Affairs)
- Jim Bausell, NRECA (Vice President of Business Development)
- Zan McKelway, NRECA (Vice President of Communication)
- Mary McLaury, NRECA (Vice President of Education and Training)
- David Mohre, NRECA (Executive Director of Energy and Environment)
- Ed Torrero, NRECA (Executive Director of the Cooperative Research Network)

Engineering Advisory Board

The Engineering Advisory Board (EAB) provides support to the Engineering Team. It will meet three times a year for the duration of the project. The role of EAB members will be to share their deep experiences and provide guidance and advice to the project from an outside perspective. One role that the EAB will fill is to make sure that the activities of the project serve the needs of the power industry as a whole and society at large. The EAB will consist of:

- *William LeBlanc, President of the Boulder Energy Group.* Mr. LeBlanc has worked for Pacific Gas & Electric Company (PG&E), the Electric Power Research Institute, and E Source. He has specialized in demand response and load management from the beginning of his career in 1985. His recent experience as a Senior Advisor to E Source is focused on energy efficiency and demand response programs.
- *Frances Cleveland, President and Principal Consultant of Xanthus Consulting.* Ms. Cleveland is a long-time consultant to the electric power industry. She is supporting NIST in the development of the interoperability roadmap. In addition to consulting for investor-owned utilities, public utilities, and co-ops, Ms. Cleveland has done work for the Electric Power Research Institute, the California Energy Commission, and has been very active in the International Electrotechnical Commission (IEC) and the IEEE standards activities.
- *Eric Cody, President Cody Energy Group.* Mr. Cody has had a 23-year electric utility career that includes a dozen years as vice president of several National Grid USA (formerly known as New England Electric System) companies. Mr. Cody brings executive level utility experience in managing IT resources to the EAB.

Software and hardware vendors will be consulted throughout the project to ensure that any innovations in interoperability will be supported by the vendor community. When soliciting participation from the vendors, this project will draw heavily from the companies that are MultiSpeak Vendor Members (see below). We may also reach out to vendors beyond this list in order to get input from other categories of vendors.

MultiSpeak Initiative Advisory Board

The nine-member MultiSpeak Advisory Board taps the expertise of software providers and users from utilities to provide advice on the future direction of the MultiSpeak interoperability standard and the software integration needs of utilities. The Advisory Board focuses on making MultiSpeak a better product for utilities. This project will draw on the Board's expertise under the guidance of the Board chairman: Gregory Wolven, Director of Engineering, WIN Energy REMC, Indiana.

MultiSpeak Vendor Members

MultiSpeak's Vendor Members support the development of the MultiSpeak interoperability standard, and as such have an interest in making sure that innovations in interoperability have practical applications can be supported by their products. The MultiSpeak Vendor Members are:

- Aclara (DCSI TWACS)
- Advanced Control Systems
- Apogee Oracle
- C3-Ilex OSECS
- Carina Technology
- Cooper Power
- Cannon Technologies
- NISC
- NRTC
- Olameter, Inc.
- Open Systems International
- Oracle
- OSECS
- Ovace A Mamnoon

- Central Service Association
- Clevest Solutions
- Cooperative Response Center
- Cornice Engineering, Inc.
- Daffron
- Elster Integrated Solutions
- EPRI
- EnerNex
- Enspiria Solutions
- ESRI
- Exceleron Software
- GeoNav Group
- Landis + Gyr
- Meltran, Inc.
- Milsoft
- N-Dimension Solutions
- Nexant, Inc.
- Partner Software
- Powel
- Power Delivery Associates
- Power System Engineering
- Professional Computer Systems
- Progress Software
- QEI
- RMA Engineering, LLC
- SageQuest
- SEDC
- Siemens
- SpatialNet
- Survalent Technologies
- Tantalus
- Telvent/Miner & Miner
- Trimble
- UISOL
- Wireless Matrix
- Xtensible Solutions

Electric Cooperatives

Each participating electric co-op has a Principal Investigator, who will oversee the project work in his or her service area. They are:

Adams Electric Cooperative, James H. Thomson (General Manager)
Adams-Columbia Electric Co-op, David Ziarnik (Engineering Manager)
Clarke Electric Cooperative Inc., William S. Freeman (General Manager/CEO)
Consumers Energy, Brian Heithoff (CEO/General Manager)
Corn Belt Power Cooperative, Jim Vermeer (Vice President, Business Development)
Delaware County Electric Cooperative Inc., Paul DeAndrea (Manager, Engineering and Technology)
Flint EMC, Titus Diamond (Chief Operating Officer)
Kauai Island Utility Cooperative, Michael Yamane (Senior Electrical Engineer)
Menard Electric Cooperative, Lynn Frasco (General Manager)
New Hampshire Electric Cooperative, James Bakas (Vice President of Engineering and Operations)
Nolin RECC, Greg Harrington (System Engineer)
Owen Electric Cooperative Inc., Jim See (Senior Vice President of System Planning and Reliability)
Prairie Power Inc., Robert Reynolds (Senior Director, Planning Operations)
Salt River Electric Cooperative Corp., Tim Sharp (Vice President, Operations)
Snapping Shoals EMC, Mike Milligan (System Engineer)
United REMC, Robert Kolling (Manager of Engineering)
Washington-St. Tammany Electric Co-op, Charles Hill (Manager of Engineering and Operations)

5. Project Performance Sites

For NRECA's demonstration, performance sites must be considered to be the service areas of the participating co-ops. The reason is obvious when one considers the quantity of Smart Grid devices to be deployed under the project. Here we offer highlights of a few common elements that are characteristic of the participants and indicate how they support DOE's Program Objectives (FOA p. 8 and Appendix Table A.5). We have entered only one site on the form, since the form will not accommodate all of our sites. Detailed information on each site is attached as a separate file.

Attribute: Low Density

Our project brings the most rural of America into the Smart Grid Demonstration Program. These regions are often under-represented in studies. Gaining data and understanding of the Smart Grid applications for low-density utilities is essential to DOE's work. For example, Iowa-based Corn Belt Power Co-op and its 10 distribution co-ops serve 40 counties and 9 out of 10 meters in the Corn Belt system serve farms. Four of these co-ops have fewer than 2,000 members. Many of these co-ops must still send staff out long distances to read meters. Other rural co-ops taking part in the study include: Adams Electric Co-op, 3.8 consumers per mile; Menard Electric Co-op, 4 consumers per mile; and Clarke Electric Co-op, 2.9 consumers per mile.

Adams and Menard will deploy and study Advanced Volt/VAr Control. Adams, Clarke and Menard will deploy self-healing feeders. Corn Belt and its co-ops will deploy an AMI-enabled two-way demand response system.

Addresses DOE Program Objectives: Lower T&D Losses, Lower Peak Demand, Lower O&M Losses, Reduce Impacts of Global Warming.

Attribute: Low Consumer Income Levels

Maintaining affordable electricity is a core objective of consumer-owned electric co-ops and NRECA. Co-ops serve a disproportionate number of consumers who live below the median income level. Examples of these include Consumers Energy and Clarke—an RUS hardship borrower owing to below-the-median income in most of the counties it serves. In the service area of two participating Kentucky co-ops—Nolin and Salt River—more than 20 percent of households have an annual income less than $20,000.

Consumers, Clarke, and Nolin are pursuing time-sensitive pricing pilots using AMI, which may help avoid the cost of building additional peaking capacity or purchasing power at very high costs during peaks. They are also planning in-home energy usage pilots, studying the effect of these technologies on peak demand and conservation.

Addresses DOE Program Objectives: Lower Electricity Costs.

Attribute: Service Areas Prone to Natural Disasters

Washington-St. Tammany Electric Co-op, LA, has been ravaged by three hurricanes in the last four years: Katrina, Gustav, and Ike. Clarke is still in the process of rebuilding more than 200 miles of line damaged by an ice storm. Part of Adams Electric's service territory is located in the Mississippi River flood plain; flooding there can wash away electric facilities and require lines to remain de-energized for 2-3 months until waters recede.

To this end, Washington-St. Tammany, Adams, and Clarke are all deploying self-healing feeders.

Addresses DOE Program Objectives: Lower O&M Costs, Reduced Cost of Power Interruptions.

Below, find more detail about individual cooperatives and their service areas. Note that equipment installation will be either at consumers' meters or at substations, offices, or other facilities operated by the cooperatives. The cooperatives hold all necessary deeds and leases to their own facilities, and so have the right to use those sites for the duration of the project. Installation of consumers' meters will be done with the cooperation and consent of the consumer.

<table>
<tr><td>Adams Electric Cooperative</td><td>Business Address: 700 East Wood , Camp Point, IL 62320-0247
Service Area: In western Illinois
Contact: James H. Thompson, jthompsn@adams.net, (217) 593-7701</td></tr>
<tr><td colspan="2">Adams Electric Co-op has 41 employees and serves over 8,000 members and maintains over 2,190 miles of electric lines in rural Adams, Brown and Schuyler counties, as well as parts of Pike, Hancock, McDonough and Fulton counties in Illinois.

Adams has a low consumer density—on average, 3.8 consumers per mile. However, density is higher in the area bordering the urban center of Quincy, IL, and this area has also seen growing commercial and residential demand. Part of Adams' service territory is located in the Mississippi River flood plain; flooding there can wash away electric facilities and require lines to remain de-energized for 2–3 months until waters recede (for instance, in June 2008). Adams deployment of distribution automation will make its system more reliable in flood areas.</td></tr>
<tr><td>Adams-Columbia Electric Co-op</td><td>Business Address: 401 East Lake St. Friendship, WI 53934
Service Area: In south-central Wisconsin
Contact: David Ziarnik, dziarnik@acecwi.com, (608) 339-3346</td></tr>
<tr><td colspan="2">Adams-Columbia Electric Co-op has over 112 employees and serves over 19,000 farms and residences, as well as mixed commercial, irrigation, and non-residential members through 5,324 miles of electric lines in 12 mostly rural counties of south-central Wisconsin.

Adams-Columbia has a low consumer density—on average, 6.8 customers per mile—coupled with a large percentage of seasonal accounts (approximately 40 percent). Many seasonal customers are from more urban areas and, where they may already have been exposed to some form of Smart Grid initiative.

With the consumer absent, outages in the off-season are more likely to go unreported. Adams-Columbia's plan for deploying distribution automation for increased quality and reliability may offer compensation.</td></tr>
<tr><td>Clarke Electric Cooperative Inc.</td><td>Business Address: 1103 North Main St. Osceola, IA 50213
Service Area: In south-central Iowa
Contact: William S. Freeman, wfreeman@cecnet.net, (641) 342-2173</td></tr>
<tr><td colspan="2">Clarke Electric Co-op, Inc. is based in Osceola, Iowa, and serves over 5,000 members through 1,806 miles of electric lines in Clarke, Decatur, Lucas, Madison, Ringgold, Union, Warren, and Wayne counties.

Clarke Electric has a low consumer density—on average, 2.9 customers per mile—and is still in the process of rebuilding in excess of two hundred miles of line due to an ice storm in December 2007. The co-op is an RUS hardship borrower due to below-the-median income in most of the counties it serves.

Consequently, holding down consumer costs is a concern. Pilot programs for in-home displays, time-sensitive rates, and the control of water heaters and air conditioners would reduce the need for new generation—and thus also keep consumer costs down.</td></tr>
<tr><td>Consumers Energy</td><td>Business Address: 2074 242nd St., Marshalltown, IA 50158
Service area: In central Iowa
Contact: Brian Heithoff, bheithoff@consumersenergy.coop, (641) 752-1593</td></tr>
</table>

Consumers Energy serves over 5,000 electric and natural gas members and customers in six counties throughout Central Iowa: Marshall, Jasper, Polk, Tama, Story and Hardin. Consumers Energy has a low consumer density—on average, 4.4 consumers per mile. The co-op's consumer's income levels are below the national average. Relative to other co-ops, it has an unusually high number of renters. Consumer Energy's pilot programs for Internet-based energy usage portals, in-home energy displays, and time-sensitive rates will give the co-op's consumers information on how to save money and become active participants in demand response.	
Corn Belt Power Cooperative	*Business Address: 1300 13th Street North, Humboldt, IA 50548* *Service area: In north Iowa* *Contact: Jim Vermeer, jim.vermeer@cbpower.coop, (515) 332-2571 (227)*
Corn Belt Power Co-op, headquartered in Humboldt, Iowa, is a generation and transmission (G&T) electric cooperative owned by its member co-ops across northern, middle Iowa. CBP supplies electricity to member cooperatives that serve over 43,000 customer farms, rural residences, small towns, businesses and industries in 41 counties in northern Iowa. Corn Belt's 10 participating distribution cooperatives have densities that range from 1.7 to 3 meters per mile. Most of the consumers served by the Corn Belt system are in rural areas. Four cooperatives serve less then 2,000 meters. Many of these cooperative must still send staff around their large service area to read meters. Installing an AMI system will allow these cooperatives to not only save money but reduce their overall carbon footprint. Iowa ranks as the number one state in poultry, pork, soybean, and corn production. Consequently 90 percent of the meters in the Corn Belt system are located on farms. In addition 60 percent of Corn Belt's total sales are commercial and industrial. Installing the AMI system will allow Corn Belt to initiate a demand response program and control the 50 MW of distributed generation currently on its system. They will be able to better manage the demanding agricultural loads, especially in the fall when the system peaks due to high demand from farms drying their crops. Recently Iowa became the number-two state in installed wind capacity. AMI will provide Corn Belt and its members with better intelligence on the costs of wind and the output of facilities throughout the day. This data will be used to better take advantage of this vast renewable resource in Iowa. The participating distribution companies are listed below. 1. Butler County REC 2. Calhoun County REC 3. Franklin REC 4. Glidden REC 5. Grundy County REC 6. Humboldt County REC 7. Iowa Lakes Electric Cooperative 8. Midland Power Cooperative 9. Prairie Energy Cooperative 10. Sac County REC	
Delaware County Electric Cooperative Inc.	*Business Address: 39 Elm Street, Delhi, NY 13753-1208* *Service area: In southern New York* *Contact: Paul DeAndrea, paul.deandrea@dce.coop, (607) 746-2341*
Delaware County Electric Co-op, Inc., headquartered in Delhi, NY, provides electric service and related products to members throughout Delaware, Schoharie, Otsego and Chenango counties. Delaware County operates 780 miles of line and 6 substations; serves 5,200 consumers; and has a density of 6.8 consumers per mile.	

<table>
<tr><td colspan="2">The cooperative's service area is often hit by snowstorms in October and December. These often result in outages for 30 percent of their consumers; these outages can last 3–5 days.</td></tr>
<tr><td>Flint EMC</td><td>Business Address: 3 S. Macon Street, Reynolds, GA 31076
Service area: In west-central Georgia
Contact: Titus Diamond, tdiamond@flintemc.com,
(478) 988-3552</td></tr>
<tr><td colspan="2">Flint EMC, is based in Reynolds, Georgia, and provides energy services to residential (88 percent), commercial (11 percent), industrial and agricultural members in parts of 17 central Georgia counties. Their service territory stretches from Warner Robins Air Force base in Houston County to Columbus. The area near Warner Robins is the only urban population within the system. Flint has 230 employees and serves more than 80,000 meters. Flint EMC has a consumer density of 13 consumers per mile.

Pilot programs for in-home displays, critical peak pricing, and consumer internet dashboards with real-time energy usage will help rural customers keep track of energy costs.</td></tr>
<tr><td>Kauai Island Utility Cooperative</td><td>Business Address: 4463 Pahee St., Suite 1, Lihue, HI 96766
Service area: The Island of Kauai
Contact: Michael Yamane, myamane@kiuc.coop,
(808) 246-8208</td></tr>
<tr><td colspan="2">Kauai Island Utility Co-op, is based in Lihue, HI and serves more than 35,000 members, divided approximately into 76 percent residential, 13 percent commercial, 10 percent street lighting, and 0.4 percent industrial. The co-op takes environmental concerns very seriously and has committed to providing 50 percent of its power from renewable, non-polluting means by 2023.

Kauai Island Utility has a consumer density of 25 consumers per mile. Residential usage in the co-op's service area is relatively low compared to the rest of the nation due to high rates and reliance on liquid fossil fuels. Also, because of the mild climate, energy usage is driven more by water heating and refrigeration and less on heating and cooling. Kauai Island Utility is a vertically integrated utility—a full-service provider of generation, transmission, and distribution to its members.

By deploying load control of water heaters, Kauai Island Utility will address one of the major elements of its load. The co-op's pilot programs for Internet-based energy usage portals, in-home energy displays, and time-sensitive rates will give the co-op's consumers information on how to save money and partially offset the high cost of liquid fossil fuels.</td></tr>
<tr><td>Menard Electric Cooperative</td><td>Business Address: 14300 State Hwy 97, Petersburg, IL 62675
Service area: In central Illinois
Contact: Lynn Fransco, lfrasco@menard.com,
(217) 632-7746</td></tr>
<tr><td colspan="2">Menard Electric Co-op, is headquartered in Petersburg, Illinois, and serves over 10,000 meters with over 2,500 miles of distribution line providing rural residences, commercial and industrial businesses in Cass, Logan, Macon, Mason, Menard, Morgan, Sangamon and Tazewell counties.

Menard has a consumer density of 4 consumers per mile. Its distribution system has a higher than normal swing in load due to a high percentage of irrigation demand. The irrigation load is subject to weather variations and as a result the VAr levels can become imbalanced quickly. With the addition of Volt/VAr compensators, there should be a real improvement to the systems power efficiency.</td></tr>
<tr><td>New Hampshire Electric Cooperative</td><td>Business Address: 579 Tenney Mountain Hwy., Plymouth, NH 03264-3147
Service area: Throughout New Hampshire
Contact: James Bakas, bakasj@nhec.com,
(603)536-8631</td></tr>
</table>

New Hampshire Electric Co-op serves approximately 80,000 members in 115 towns and cities. It maintains over 5,400 miles of energized line that traverse nine of the 10 counties in New Hampshire. Headquartered in Plymouth, the Cooperative serves members in 10 operating districts: Colebrook, Lisbon, Sunapee, Andover, Plymouth, Meredith, Conway, Alton, Ossipee, and Raymond. New Hampshire Electric has a consumer density of 14 consumers per mile. The co-op's service area covers 10 distinct territories in all part of the state and includes ski resorts in the mountains as well as 72 islands in the lake region. New Hampshire Electric's pilot programs for in-home energy displays, time-sensitive rates, and advanced thermal storage, which will be distributed to provide a strong statistically representative sampling of its diverse membership.	
Nolin RECC	*Business Address: 411 Ring Rd., Elizabethtown, KY 42701* *Service area: In central Kentucky* *Contact: Greg Harrington, gregh@nolinrecc.com, (270) 765-6153*
Nolin RECC serves Kentucky's Hardin, Larue, Breckinridge, Nelson, Hart, Green, and Bullit counties. Nolin has 32,000 consumers, 3,700 miles of line, and 22 substations. The co-op does not have a problem with peak demand, though it does expect that its area will need new generation capacity in the next five years. Nolin has a consumer density of 11 consumers per mile. Its service area includes the distribution system for the Fort Knox Military Installation. Every two or three years, ice storms will pull part of its system offline. During last winter's ice storm, 28,000 consumers were temporarily without power. Nolin RECC's deployment of distribution automation technology—including advanced Volt/VAr control—will increase quality and reliability in its service area.	
Owen Electric Cooperative Inc.	*Business Address:* 8205 HWY 127 N, Owenton, KY 40359 *Service area: In northern Kentucky* *Contact: Jim See,* jsee@owenelectric.com, *(502) 484-3471*
Owen Electric Co-op, Inc., based in Owenton, Kentucky, serves over 50,000 members over 4,400 miles of power lines throughout its nine-county area: Boone, Campbell, Carroll, Gallatin, Grant, Kenton, Owen, Pendleton and Scott counties. Owen operates a total of 4,464 miles of line; serves 57,000 consumers; and has a density of 13 consumers per mile. Thunder- and windstorms result in several days of power outages every year. Owen expects that new generation and transmission will be needed in its area sometime during the next five years. Its deployment of advanced volt/VAr control for reducing total demand and should help defer the need for new generation, while its deployment of self-healing feeders should help the cooperative recover from storm-related outages.	
Prairie Power, Inc.	*Business Address: 2103 South Main Street, Jacksonville, IL 62651-0610* *Service area: Across central Illinois* *Contact: Robert Reynolds, rreynolds@ppi.coop, (217) 245-6161*
Prairie Power, Inc., headquartered in Jacksonville, Illinois, is an electric generation and transmission cooperative located in Jacksonville, Illinois. PPI generates, purchases and delivers over 1.6 million megawatt-hours of electricity annually to its 10 member-owned electric distribution cooperatives. PPI owns and operates approximately 594 miles of transmission lines at 138 kV, 69 kV, and 34.5 kV; 22 MW	

of coal-fired base load generation; 150 MW of oil and gas-fired peaking units; and 87 distribution and transmission substations to serve its members. PPI's distribution cooperatives provide retail electric service to over 78,131 residential, agricultural, commercial and industrial consumer-members throughout central Illinois. The distribution co-ops served by Prairie Power have a low consumer density--below 4 consumers per mile. A number of its distribution co-ops hope to reduce load through voltage reduction; the 48 regulator control panels Prairie Power will install will not only enable this sort of load reduction, but also help measure its effectiveness.	
Salt River Electric Cooperative Corp.	*Business Address: 111 W. Brashear Ave., P.O. Box 609, Bardstown, KY 40004* *Service area: In west-central Kentucky* *Contact: Tim Sharp, tjsharp@srelectric.com, (502) 348-3931*
Salt River Electric Co-op Corp., Bardstown, Kentucky, serves 46,000 members, in central Kentucky, primarily Bullitt, Nelson, Washington, and Spenser counties. Salt River operates 3,300 miles of line and 29 substations. It has a density of 12 consumers per mile. From late April to mid-September, Salt River's service area is frequently hit with severe thunderstorms that will bring the whole system down for a duration of anywhere from several hours to several days. It is hit with a severe ice storm on average once every 10 years. Salt River and the surrounding area is currently in need of new generation and transmission capacity.	
Snapping Shoals EMC	*Business Address: 14750 Brown Bridge Road, Covington, GA 30014* *Service area: In north-central Georgia* *Contact: Mike Milligan, mmilligan@ssemc.com, (770) 786-3484 (2723)*
Snapping Shoals EMC, is headquartered in Covington, Georgia, and provides electric service to about 95,000 residential, commercial and industrial consumers in an eight-county area southeast of Atlanta; Rockdale, Henry, Newton, DeKalb, Butts, Walton, Jasper and Morgan counties. The majority of the cooperative's service growth is influenced by its proximity to Atlanta. The population of Henry County has increased 93 percent over the previous 10 years, making it the fourth fastest growing county in the nation. Newton County's population has increased 45 percent. This growth is a direct result of the Atlanta economy and job market. Most of the co-op's customers commute to the Atlanta area for employment. Snapping Shoals faces a challenge keeping its grid reliable in the face of such extraordinary growth. The addition of two-way load control and critical peak pricing will push back the day that more generation will need to be added to the area, while the addition of self-healing feeder automation and Volt/VAr control will help with system reliability.	
United REMC	*Business Address: 4563 E. Markle Rd, Markle, IN 46770* *Service area: In north-east Indiana* *Contact: Robert Kolling, RKolling@unitedremc.com, (260) 758-3155*
United REMC, Markle, Indiana, has 38 employees, approximately 2,000 miles of distribution line, 13 substations and 12,000 accounts spread mostly throughout Huntington, Wells, and Allen counties. Nearly half its sales come from industrial and commercial accounts. United has a consumer density of 8 consumers per mile. Much of its service area is rural; a number of	

farms in the area produce seasonal load in autumn, when corn and soybeans are dried using artificial heat. Winds off Lake Michigan can damage lines, and with ice buildup posing a problem each winter. United expects that in the next 5 years, its area will need new generation capacity as well as new transmission lines. Its deployment of advanced volt/VAr (for lowering total demand) and its pilot programs for critical peak pricing and water heater and AC load control should defer the need for new generation.	
Washington-St. Tammany Electric Co-op	*Business Address: 950 Pearl Street , Franklinton LA, 70438* *Service Area: In eastern Louisiana* *Contact: Charles Hill, chill@wste.coop, (985) 839-3562*
Washington-St. Tammany Elec. Co-op, based in Franklinton, Louisiana, has over 124 employees serving over 41,188 accounts, with 136 miles of transmission lines, over 5,400 miles of distribution lines, 2 transmission substations, 3 transmission switching stations and 30 distribution substations. Washington-St. Tammany has a consumer density of 8 consumers per mile. Its service area is located just north of New Orleans and serves what can be considered suburban New Orleans. This area has been affected by three hurricanes in the past four years: Katrina, Gustav and Ike. Its deployment is of self-healing feeders to study and improve reliability.	

6. Statement of Project Objectives (SOPO)

This section provides a succinct summary of our approach, adhering to the five-page limit. While the information here provides a high-level view, we recommend that reviewers rely on the Project Management Plan, which provides substantially more detail. There, we decompose the project into about 150 tasks, and explain the activity in each.

A. Project Objectives

The objectives of the proposal project are as follows:

Core Objectives: End-to-End Demand Management

1. Demonstrate advanced two-way metering infrastructure and conservation voltage reduction programs to study technology readiness and impact on peak demand.
2. Advance systems integration and cyber security controls that will enable end-to-end control and sophisticated pricing signals and load control.
3. Quantify the impact of in-home energy use display devices for household accounts in terms of energy use reduction and shifts in time of energy use, and describe the shifts in customer energy usage behavior in response to the presence of in-home displays and, if applicable, price signals.
4. Support DOE's SGDP studies, Clearinghouse, and industry/public outreach.

Core Objectives: Advanced Distribution Grid Management

1. Develop and test MultiSpeak specification extensions and additional software development to enable and advance systems integration of multiple AMI, meter data management systems, self-healing feeders, and advanced Volt/VAr programs.
2. Demonstrate Self-Healing Feeders for low density utilities and Advanced Volt/VAr Programs for Reducing Losses. Learn what works, at what cost, and what doesn't work, and to report on case studies and best practices.
3. Measure impact on power quality and reliability metrics of these programs and report on leading approaches.
4. Support DOE's SGDP studies, Smart Grid Clearinghouse, and industry/public outreach.

B. Project Scope

The core of the project is the installation and study of over 153,000 Smart Grid components, their configuration, and integration into the co-ops operations. As noted previously, we intend to do this in four tranches, each of about four months duration. The purpose of this approach is to provide tight management and to allow for improvement of our processes over the course of the project. The overarching tasks are as follows:

Project Management. The Project Management task includes development of the operation Project Management Plan with DOE at the outset of the project, revision of the plan after each tranche, reporting, performance tracking and remediation of any deficiencies, and oversight of the three tracks of the project – Data Collection and Study, Administration, and Engineering.

NEPA Compliance. In the NEPA compliance task we will address all environmental consideration and obtain consent to proceed. We expect to solicit blanket waivers or approval for classes of technology with zero or minor impacts. This expectation is based on precedents.

MultiSpeak Extensions. We will extend MultiSpeak to address inter-application interfaces required to achieve the required business objectives of the project, including market-to-customer demand response and distribution grid management. These interface definitions will lower the cost and effort required to deploy Smart Grid technology. We will disseminate the specification at no cost at the conclusion of the project. Cyber security will be addressed in this stage.

Establish Data Collection, At the outset of the project we will develop an automated data collection system that collects the data within co-ops, formats it for transmission to NRECA, validates the data for internal consistency and reasonableness, and sends the data to NRECA where it is checked again and stored in a database.

Engineering. The engineering tasks address the actual process of specification, installation, configuration and integration. A central engineering team will support the engineers at the co-ops.

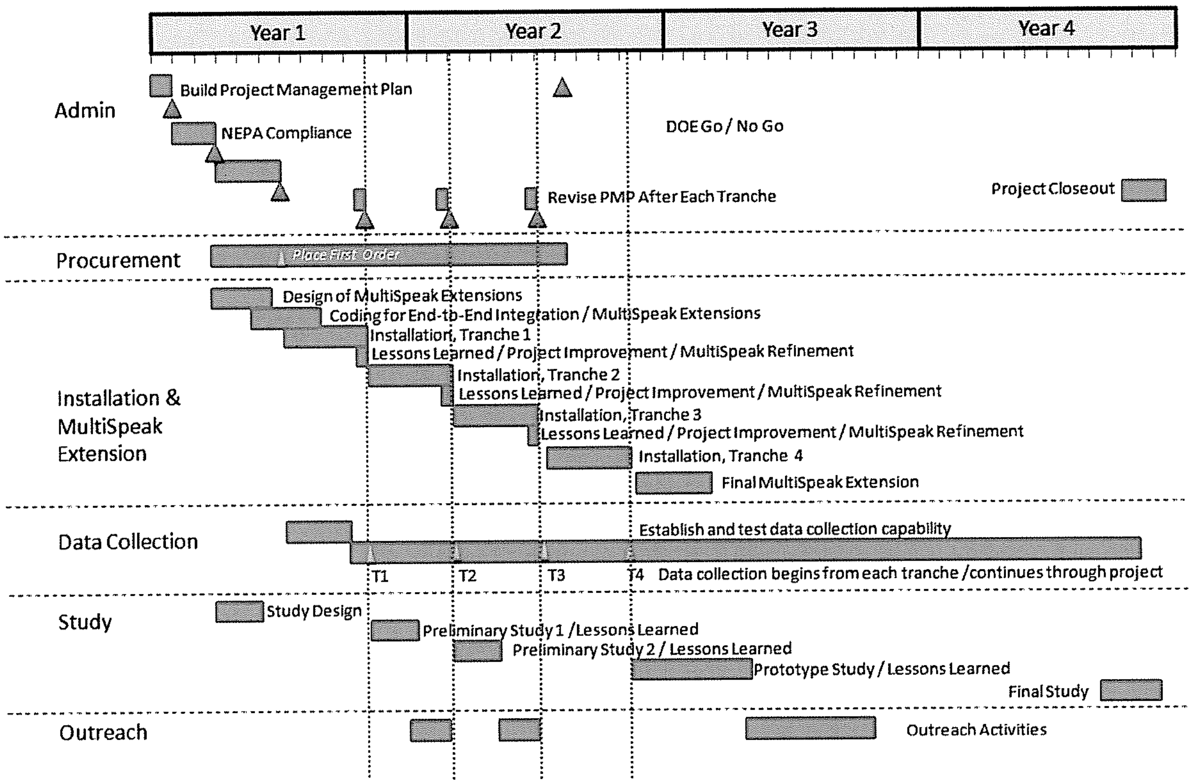
Procurement. A professional procurement team has been assembled to handle all purchasing including aspects such as dispute resolution. A critical issue that must be resolved with the engineering team is timing of purchases to manage risk.

Data Collection. Data will be collected for the duration of the project using the data collection system developed in an earlier task. We have separated development of the system from actual data collection because they require fundamentally different skills. We will collect (or impute) data for all of the study sites for the six months through the end of the project. We will also collect data for the same period for comparable sites.

Analysis. NRECA will execute a series of cost-benefit studies (specified earlier in the narrative) at the end of the project and support DOE in its study. The study design will be developed jointly with DOE at the start of the project. We will conduct preliminary studies after the first and second tranches of installation as part of the process improvement effort and to refine the study methodology. We also plan to do qualitative "lessons learned" and "best practices" studies at the intermediate points and at the conclusion of the project.

Outreach. NRECA will conduct outreach activities through the duration of the project and support efforts from DOE in this regard. This is a priority for NRECA as it is central to our mission to support our members. We will prepare reports and hold seminars and Webinars.

PROJECT SCHEDULE



C. Tasks to Be Performed

Our work breakdown structure (WBS) has approximately 150 tasks, as shown on the next page. Space does not permit a narrative in the SOPO, but a detailed narrative is provided in the Project Management Plan.

Work Breakdown Structure	
101 Project Award / Start Project	107.63 Tranche 3 Data Collection
102 Project Management	107.81 Tranche 4 Control Group Selection

102.1 Draft New PMP
102.3 DOE Review
102.4 DOE Approval Of PMP
102.5 Monthly Reporting
102.6 PMP Revision 1
102.7 PMP Revision 2
102.8 PMP Revision 3
102.9 Closeout
103 NEPA Compliance
103.1 Analysis
103.2 Draft Submission
103.3 DOE Review
103.4 Address Deficiencies
103.5 NEPA Approval
104 Multispeak Extensions
104.1 Planning—Design Of The Standards
104.2 Tranche1 Define
104.3 Tranche1 Design
104.4 Tranche 1 Code
104.5 Tranche 1 Test
104.6 Tranche 1 Deploy
104.7 Tranche 1 IV&V
104.8 Update Plan
104.9 Tranche 2 Define
104.10 Tranche 2 Design
104.11 Tranche 2 Code
104.12 Tranche 2 Test
104.13 Tranche 2 Deploy
104.14 Tranche 2 IV&V
104.15 Update Plan
104.16 Tranche 3 Define
104.17 Tranche 3 Design
104.18 Tranche 3 Code
104.19 Tranche 3 Test
104.20 Tranche 3 Deploy
104.21 Tranche 3 IV&V
104.22 Update Plan
104.23 Tranche 4 Define
104.24 Tranche 4 Design
104.25 Tranche 4 Code
104.26 Tranche 4 Test
104.27 Tranche 4 Deploy
104.28 Tranche 4 IV&V
105 Establish Data Collection
105.1 Analysis Plan
105.2 Data Requirements
105.3 Collect System Configuration Data
105.4 Construct NRECA Database
105.5 Data Validation Software
105.6 Develop New HW Data Collection Software
107.82 Tranche 4 Post Install Data Test
107.83 Tranche 4 Data Collection
109 Analysis
109.1 Analytical Design Review With DOE
109.3 Preliminary Analysis 1
109.4 Preliminary Analysis 2
109.5 Final Analytical Plan
109.7 Final Cost / Benefit Analysis
109.10 Best Practices Report
109.12 Final Report
111 Outreach
111.1 Interim Report 1
111.3 Interim Report 2
111.5 Post Install Reports
111.6 Tech Surveillance
111.7 Seminars
111.8 Webinars
113 Procurement
113.1 Initial Requirements
113.2 Tranche 1 Requirements
113.3 Tranche 1 Solicitation
113.4 Tranche 1 Purchase
113.5 Tranche 1 Delivery / Acceptance
113.6 Tranche 2 Requirements
113.7 Tranche 2 Solicitation
113.8 Tranche 2 Purchase
113.9 Tranche 2 Delivery / Acceptance
113.10 Tranche 3 Requirements
113.11 Tranche 3 Solicitation
113.12 Tranche 3 Purchase
113.13 Tranche 3 Delivery / Acceptance
113.14 Tranche 4 Requirements
113.15 Tranche 4 Solicitation
113.16 Tranche 4 Purchase
113.17 Tranche 4 Delivery / Acceptance
113.18 Dispute Resolution
210 Tranche 1 Installation
210.1 Legal / Admin Issues Related To Site
210.2 Recruit Participants
210.3 Receipt Of Equipment
210.5 Installation & Configuration
210.6 Test
210.7 Integration With System
210.8 Test
210.9 Operation / Refinement
220 Tranche 2 Installation
220.1 Legal / Admin Issues Related to Installation
220.2 Recruit Participants
220.3 Receipt Of Equipment
220.4 Installation

105.7 Develop Control Group Data Collection Software 105.8 Data Transfer Tests 105.9 Tranche 1 Ready for Data Collection 105.10 Tranche 2 Extensions and Refinement 105.11 Tranche 2 Data Transfer Tests 105.12 Tranche 2 Ready for Data Collection 105.13 Tranche 3 Extensions and Refinement 105.14 Tranche 3 Data Transfer Test 105.15 Tranche 3 Ready for Data Collection 105.16 Tranche 4 Extensions 105.17 Tranche 4 Data Transfer Tests 105.18 Tranche 4 Ready for Data Collection 105.19 Backfill Data **106 Engineering** 106.1 Common Engineering / Coordination 106.2 Tranche 1 Details 106.21 Internal Engineering Review 106.22 DOE Review and Approval 106.3 Tranche 2 Details 106.31 Internal Engineering Review 106.32 DOE Review and Approval 106.4 Tranche 3 Details 106.41 Internal Engineering Review 106.42 DOE Review and Approval 106.5 Tranche 4 Details 106.51 Internal Engineering Review 106.52 DOE Review and Approval **107 Data Collection** 107.21 Tranche 1 Control Group Selection 107.22 Tranche 1 Post Install Data Test 107.23 Tranche 1 Data Collection 107.41 Tranche 2 Control Group Selection 107.42 Tranche 2 Post Install Data Test 107.43 Tranche 2 Data Collection 107.61 Tranche 3 Control Group Selection 107.62 Tranche 3 Post Install Data Test	220.5 Test 220.6 Integration With System 220.7 Test 220.8 Operation / Refinement **230 Tranche 3 Installation** 230.1 Legal / Admin Issues Related to Installation 230.2 Recruit Participants 230.3 Receipt of Equipment 230.4 Installation 230.5 Test 230.6 Integration with System 230.7 Test 230.8 Operation / Refinement **240 Tranche 4 Installation** 240.1 Legal / Admin Issues Related to Site 240.2 Recruit Participants 240.3 Receipt of Equipment 240.4 Installation 240.5 Test 240.6 Integration With System 240.7 Test 240.8 Operation / Refinement

Success Criteria at Decision Points

We have designed the project with nine decision points.

Decision Point	Task	Description
1	102.4	DOE Approval of Revised Project Management Plan
2	103.5	DOE Approval of NEPA Application
3	106.22	DOE Approval of Engineering Plan
4	102.6	Tranche 1 – Satisfactory Results (PMP Revision 1)
5	106.32	DOE Approval of Engineering Plan for Tranche 2

6	102.7	Tranche 2 – Satisfactory Results (PMP Revision 2)
7	106.42	DOE Approval of Engineering Plan for Tranche 3
8	102.8	Tranche 3 – Satisfactory Results (PMP Revision 3)
9	106.52	DOE Approval of Engineering Plan for Tranche 4

D. Deliverables

Task	Deliverables
102 Project Management	Operational Project Management Plan
102.6 PMP Revision 1	Update Project Management Plan
102.7 PMP Revision 2	Update Project Management Plan
102.8 PMP Revision 3	Update Project Management Plan
102.9 Closeout	Project Closeout Report
103.1 Analysis	Analysis of Environmental Impact / Mitigation Plan
103.2 Draft Submission	Draft NEPA Filing
103.4 Address Deficiencies	Final NEPA Filing
104.1 Planning	Plan for MultiSpeak Development Phasing
104.13 Develop Detailed Use Cases and Interface Designs	Use Cases and Initial Interface Designs
104.16 Formalize Interface Design as Part of the MultiSpeak Standard	Updated MultiSpeak Specification
105.2 Data Requirements	Data Collection Plan
106.1 Common Engineering / Coordination	High Level Engineering Plan
106.21 Internal engineering review	Tranche 1 Detailed Engineering Plan Refinements to MultiSpeak Protocol
106.31 Internal engineering review	Tranche 2 Detailed Engineering Plan Refinements to MultiSpeak Protocol
106.41 Internal engineering review	Tranche 3 Detailed Engineering Plan Refinements to MultiSpeak Protocol
106.51 Internal engineering review	Tranche 4 Detailed Engineering Plan Final MultiSpeak Protocol
107.23 Tranche 1 Data Collection	Data From Tranche 1 Sites
107.43 Tranche 2 Data Collection	Data From Tranche 2 Sites
107.63 Tranche 3 Data Collection	Data From Tranche 3 Sites
107.83 Tranche 4 Data Collection	Data From Tranche 4 Sites
109 Analysis	Draft Plan for Analysis
109.3 Test Analysis 1	Intermediate Analytical Results
109.4 Test Analysis 2	Intermediate Analytical Results
109.5 Final Analytical Plan	Final Plan for Analysis
109.7 Final cost / benefit analysis	Final Analysis
109.10 Best Practices Report	Best Practices Reports

111.1 Interim report 1	Tech Surveillance on Tranche 1 Installs
111.3 Interim report 2	Tech Surveillance on Tranche 1 Installs
111.5 Post install reports	Final Best Practices Report, Final Data
111.6 Tech Surveillance	Multiple Tech Surveillance Special Topics
111.7 Seminars	Seminars for Co-op Members
111.8 Webinars	Webinars for Co-op Members

E. Reporting, Briefings and Technical Presentations

NRECA will provide monthly reporting and will provide briefings and technical presentations as requested. We have assumed that these will occur quarterly for the duration of the project. In addition, DOE will be invited to attend and participate in seminars and webinars hosted by NRECA for outreach.

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