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THE ECONOMIC IMPACT OF METHANE GENERATION ON DAIRY FARMS

A MICRO-ANALYTIC MODEL

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ABSTRACT

The object of this paper is to perform an analysis of the economic efficiency of methane generation on a typical 65-cow dairy farm, juxtaposed against prices and costs of auxiliary energy supplied by rural electrification. The most efficiently sized methane generation option examined is the use of methane to fuel a 30 kW generator with sales of surplus energy fed back to the utility. Whereas this option is still more expensive than present prices for electricity, this would not be the case under assumptions of escalations in relative fuel prices. On an individual farm basis, the economy is made better off by methane generation under this option by $195 per year, assuming electricity is priced at its marginal opportunity costs. The utility would incur $734 in revenue losses, but this figure represents the commensurate decrease in utility capacity and fuel. The merits of setting electricity tariffs equal to marginal costs are evidently part of the incentive for farmers to install this option. Given several scenarios of differently sized methane generators, the utility would promote the smallest facility for the farm, which in turn may be the least efficacious for the economy as a whole. This may conflict with national efficiency criteria so, therefore, regulation at the interface between the farmer and utility would have to be exercised.

INTRODUCTION

The concern for declining supplies of non-renewable fossil fuels, increasing pollution, the potential of nuclear hazard and rising fuel and electric rates, have brought increasing attention to "exotic" sources of energy. One such source is methane generation from organic materials. The typical process is anaerobic digestion by microorganisms, producing methane and carbon dioxide as by-products. An analysis of the applicability of this process versus conventional utility generation for small dairy farms is particularly worthwhile in New England or similar places where a profuse amount of such farming activity is apparent in a small land area and the cost of conventional fuels is extremely high. The object of this paper is to analyze the economic efficiency of methane generation on a typical 65-cow dairy farm, juxtaposed against prices and costs of auxiliary energy supplied by rural electrification.

METHOD OF ANALYSIS

A four-module model was constructed in order to permit the authors to: (1) assay the peak and average annual demand for energy by the farm in peak and off-peak periods; (2) approximate the costs to society of electric utility generation; (3) estimate the farmers' costs of methane generation; (4) estimate the farmers' total costs versus the utilities' total costs and revenues.

The model is subdivided into nine steps. The steps are inclusive of a number of assumptions and also reflect data collected from a random sample of 40 farm units in central Massachusetts during the Spring of 1975 and from Massachusetts Electric, the utility that serves them*. The model was run for three separate scenarios for methane generation:

(1) 45.6 m^3 digester and 12.5 kW generator;
(2) 76.0 m^3 gallon digester and 30 kW generator; and
(3) same as (2) but with selling excess power to the utility.

The model describes the interface between methane generation of electricity for farm and farm house use and electric utilities [1]. Simply stated the model works in the following fashion. The average annual and peak electric demands of a conventional farm are determined. The portion of these demands that can be satisfied by methane generation of electricity is estimated. The impact of these demands on the electric utility is measured, calculating the increment in long- and short-run costs incurred. Economic efficiency comparisons are made between two farms, one conventional, the other with methane generation, from the point of view of the utility, the farm owner, and society.

THE MODEL

Step I

The performance of a "typical" 65-cow farm within the service area was determined. "Typical" is defined as the average energy use characteristics of the sample of dairy farms. Loads include all farm uses, including in-house resistance heating, domestic use, barns, out-buildings, refrigeration, milking, water pumping and electric conveyance vehicles.

The heating demands of the farm house were remodeled under peak and extreme weather conditions to determine the temporal energy demands in kWh and peak demands in kW. The non-heating loads were determined by interviews with a sample of 40 dairy farmers in central Massachusetts [2]. The portion of total and peak demands provided by methane powered electrification is then estimated based upon the characteristic and mode of methane generation employed.

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*The cost of electric generation in Massachusetts is somewhat greater than in other parts of the United States. However, the generality of the analysis presented here should hold, especially if projected in the near-term future.

Step II — Short-run costs

After the electrical performance of conventional and methane farms has been calculated, the costs of providing all or part of demands by the utility are determined. Utility costs can be subdivided into energy and capacity costs. Short-run costs include the cost of fuel and variable operation and maintenance associated with additional output. If use is zero, short-run costs are zero. The magnitude of short-run costs for specified farm loads is estimated through use of the incremental fuel and operation and maintenance cost of the utility during various periods increased proportional to transmission losses. As load on the system increases, less efficient generation is used, and short-run costs rise. By specifying energy demands by the farm during these periods, the addition to short-run costs for the farm load is determined. The terms "short-run" costs and "long-run" costs are operationalized for this analysis. They are not necessarily coincident with other interpretations of standard terminology in economic theory.

Step III — Long-run costs

The other salient component of utility costs is the expansion of generation, transmission and distribution capacity to meet peak demands. Additional growth in demand may cause acceleration of the capacity construction schedule. The long-run costs of Massachusetts Electric were determined through use of the Cicchetti, Gillen and Smolensky marginal cost model, taking into account alternative generation schemes, interest rates, losses and reserve margins [3].

Step IV — Rate schedule of utility

A crucial factor in the farmer's analysis of generation alternatives is the utility's rate structure. In this study we examine two possible rate schedules.

One is the existing average cost declining block rate structure. As total consumption increases the per unit price of energy declines. This rate is based upon historical costs and revenues requirement. The average block is $.034/kWh for the farmer on the Massachusetts Electric grid.

The other rate structure examined is marginal cost pricing by time of day. Under this structure, the price of electricity reflects the long- and short-run costs of additional output at various times. The result is a peak, off-peak pricing scheme with a higher rate during periods of peak loads and a low rate at all other times [3,4]. Massachusetts and nearly twenty other states are considering the adoption of marginal cost pricing through mandates of their public utility commissions [5]. The marginal cost algorithm used is precisely that developed by Cicchetti et al. [3, 4].

Marginal cost or peak load pricing is receiving much consideration from both public utility commissions and consumer groups as an important alternative rate schedule for the future. One of the rationales for marginal cost pricing is that charging a higher price during peak periods will result in shifted use from peak to off-peak periods. The magnitude of this shift is expressed in the cross price elasticity of demand of peak to off-peak consumption.

To the authors' knowledge, no estimate of cross price elasticity is available at present, although there are a number of experiments in progress. As a surrogate we have used the own-price elasticity of demand for electricity as estimated by Chapman et al. [6], using a figure of −0.14 for both peak and off-peak usage. This results in a reduction of peak demand of 6.5% and an increase in off-peak usage of 5.8% in the cost analysis tables that follow. This case is presented to gauge the possible effects on demand pattern of marginal cost pricing.

Step V — Electric bill

The electric bill is calculated by multiplying the appropriate rate times the amount of consumption. For marginal cost pricing, use is divided into peak and off-peak consumption.

Step VI — Revenue to utility

The revenue to the utility is the electric bill of the farmer. Costs of metering are ignored since they are nearly identical for both the methane farm and its conventional counterpart. It is a comparison of costs of conventional power and methane generated power that is of concern.

Step VII — Total incremental costs to utility

The total costs are merely the sum of annual short- and long-run costs. These do not include all utility costs, but only those costs associated with quantity demanded, as this is the basis of comparison.

BUILDING OWNER SECTOR

Step VIII

The methane farm and conventional farm are assumed to be identical in all respects except for electrification. The incremental cost of methane includes all digester and generation costs. The annual cost is determined by amortization with a 10% interest rate over 25 years yielding a capital recovery factor of 0.110.

Step IX — Economic efficiency

The determination of some surrogate notion of the welfare economic efficiency of methane generation for electrification must take into consideration the farmer, the utility, and national economic efficiency. For the farmer, the important consideration is whether the savings in electric bills exceed the amortized cost of methane equipment. For utilities, the cost of serving a particular customer should equal revenues from that customer, in order to prevent subsidies of one class to another. Utility pricing requires that rates be designed to provide sufficient revenue for total cost recovery. For the nation, economic efficiency is achieved by minimizing the total costs of additional energy. This must be done by comparing the cost of additional methane energy and capacity with forestalled investment in conventional fuels and utility capacity. This is not unlike the equation of the long-run marginal costs of methane generation with the long-run marginal costs of auxiliary electricity.

RESULTS OF THE ANALYSIS

Farm demands

The design farm is a 65-cow dairy farm in central Massachusetts. Heating demands of the farm residence were modelled through use of TRYNSYS*, using average and extreme weather conditions for a full year of weather data. Non-heating farm loads are averaged from survey data at 40,150 kWh per year, based upon typical load profiles and interview data from 40 randomly selected Massachusetts farms. The peak demands (kW) and peak and off-peak consumption (kWh) were estimated. The electricity demand is summarized in Table 1.

TABLE 1

Farm electricity demands[a]

Total annual use in kWh.

	Peak 08.00—22.00 h Monday—Friday	Off-peak 22.00—08.00 h Monday—Friday All day Saturday, Sunday, holidays	Coincident peak demand (kW)
Heating	5,872	15,452	9.43
Non-heating	20,075	20,075	9.16
Total	25,947	36,617	18.60
Total annual use = 61,564 kWh			

[a] The portion of these demands provided by methane will be presented under each methane operation scenario.

*TRYNSYS, Transient Computer Simulation Model, University of Winsconsin Solar Energy Laboratory Computer Program, Madison, Wisc., U.S.A.

UTILITY COST

Utility costs using the marginal cost model and the marginal cost prices are presented in Table 2. The peak periods as specified by the Massachusetts Electric Co. are 08.00 to 22.00 h, Monday through Friday. All other times, including holidays and weekends, are off-peak. Marginal costs are calculated by assigning all capacity costs to peak periods.

METHANE GENERATION

The amount of bio-gas available from a methane digestor is a function of available waste, digester size, and retention time. In the calculations, a fixed retention time of 20 days for maximum production is assumed [7]. Additionally, cow wastes are relatively constant at 38.6 kg (85 lb.) per cow per day.

Based upon previous research, dilution with 1 part water to two parts manure produces a slurry of 10% volatile organic solids for digestion [8]. Using a 76.0 m^3 gallon digester and a 20 day retention time, nets 1.65 m^3 of gas per day. This is the marginal production of bio-gas that can be produced, assuming that none of the gas is directly used to warm the digester. As electrical generation is being examined, the generator coolant will be used to heat the digester. Thus, the total value of usable energy available is 3.77 GJ/day.

The costs of the methane digestion system are itemized in Table 3.

TABLE 2

Massachusetts electric marginal costs

Annual generation costs ($/kW/year)		77
Annual transmission and distribution capacity costs ($/kW/year)		4
Short-run costs ($/kWh)	— Peak	0.027
	— Off-Peak	0.019
Marginal costs ($/kWh)	— Peak	0.0501
	— Off-Peak	0.0194

TABLE 3

Digester costs

Mixing tank	$ 3,000.00
Main digester tank (fiber glass, insulated)	8,000.00
Main digester installation	2,500.00
Slurry pit	3,600.00
Slurry pump	1,000.00
Piping	1,700.00
Tank insulation	4,000.00
Instrumentation and controls	2,000.00
	$25,800.00

RESULTS OF THE ANALYSIS

Scenario I — 12.5 kW generator

In this case the farmer installs a 12.5 kW generator to provide his base load demands, and the utility supplys auxiliary power during peak demands. The 12.5 kW generator must be adjusted to 75% of its gasoline-rated power for bio-gas use. This provides an effective peak output of 9.3 kW. The generator is capable of 22% efficiency; that is, in the conversion of bio-gas to electrical energy, 78% of the energy is lost to heat and friction. It is assumed that this size power supply could meet 75% of off-peak demand and 50% on-peak energy. The peak demand of the farm is 18.6 kW, with 9.3 kW supplied by the generator; the remaining 9.3 kW is utility capacity.

Sizing the 45.6 m^3 gallon digester to provide the appropriate volume of gas with 20% reserve yields a cost of $15,480*. Additional costs are $4,000 for the generator and $1,500 for equipment to interface the farm electricity with utility supplies.

Table 4 shows the cost analysis of this scenario for the methane and conventional farm under marginal and average cost pricing.

Scenario II — 30 kW generator

This system is designed to meet all of the farms power needs both for energy and capacity. A 30 kW generator was chosen to be adequate for all peak loads. Its adjusted peak output is 22.5 kW leaving approximately a 20% reserve margin at peak. Capital costs of the system are:

Digester	$25,800.00
Generator	$ 6,500.00
	$32,300.00

Because gas production will be sufficient to meet all electric demands, utility interfacing equipment is not necessary. The cost analysis is given in Table 5.

Scenario III — 30 kW generator with power sales

This case assumes the political feasibility of selling power to the electric company at existing rates. Initiatives of this nature are being undertaken in many parts of the United States. As co-generation of electricity becomes more prevalent, this scenario will be a realistic alternative.

With maximum daily output of 1.65 m^3 per day of bio-gas, the total amount of electrical energy that could be generated is 84,510 kWh per year. Of this amount, after farm use, 22,947 kWh would be available to sell to the power company.

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*This assumes linearity of the volume—cost and gas production—volume relationship.

Cost analysis — 12.5 kW generator

Average cost pricing (ACP) and marginal cost pricing (MCP) with elasticities of 0.0 and −0.14.

	Methane farm			Conventional farm			Difference methane—conventional		
	ACP	MCP		ACP	MCP		ACP	MCP	
		0.0	−0.14		0.0	−0.14		0.0	−0.14
Farmer									
Incremental capital expense	2366	2366	2366						
Electric bill	744	823	770	2093	1991	1864			
Total expenses to farmer for electricity	3110	3189	3136	2093	1991	1864			
Additional cost to methane farmer							1017	1198	1272
Utility									
Short-run costs	523	523	490	1392	1392	1305			
Long-run costs	753	753	753	1507	1507	1507			
Total costs	1276	1276	1243	2899	2899	2812			
Revenues from customers bills	744	823	770	2093	1911	1864			
Balance to utility (costs—revenues)	532	453	473	806	908	948			
Additional cost to utility of serving methane farm over conventional							−274	−455	−475
Total additional costs of serving methane over conventional (total of utility and farm)							743	743	797

Under average cost pricing the farmer would have no incentive to vary his power sales throughout the year, and would provide a constant reliable capacity of 2.61 kW.

Under marginal cost pricing the incentive exists for as much power as possible to become sold on peak with a peak adjusted generator output of 22.5 kW. The total available supply on peak is 79,065 kWh, peak period consumption by the farm is 25,947 kWh leaving a potential of 53,118 kWh for peak period sales. However, there is not sufficient bio-gas available for this output, but all 22,947 kWh of available energy would be sold during peak periods. Additionally, the generator could be run so as to supply its 3.9 kW of generating capacity at utility peak since peak output of the farms generator is 22.5 kW and peak farm demands are estimated at 18.6 kW.

The cost analysis is given in Table 6 for this methane option. It includes a negative value for electric bill and utility costs and indicates a payment to the farmer with resultant utility savings.

CONCLUSIONS

The summary cost analysis which appears in Table 7 reveals conflicts between the best options for the utility and the methane farmer. First, the most efficiently sized methane generation option is the 30 kW generator with sales back to the utility. Of course, this is still more expensive than presently priced electricity and the marginal costs of power. However, this may not be the case under assumptions of escalation of fuel prices greater than the general rate of inflation. Also, it includes hidden subsidies (e.g. regulated natural gas prices) that utilities have which are not yet available to farmers adopting methane generation. The economy is made better off by methane generation under this option to the amount of $195 per year, assuming marginal cost pricing. The utility is worse off to the extent of $734 in revenue shortfalls. However, this revenue shortfall does represent the commensurate decrease in utility capacity and fuel costs. The farmer with this methane option is not encouraged to install the necessary equipment because his deficit would total $539.

For the national economy marginal cost pricing rate structure with this methane option is more beneficial. The merits of marginal cost rates and potential benefits to the economy appear to favor legislation enforcing such pricing and potential subsidization for the installation of methane generation on farms.

Note that the utility would opt for the smallest methane generator option, which in turn may be least efficacious for the economy as a whole. To the extent that this conflicts with national efficiency criteria, regulation at the interface between the farmer and utility must be exercised. The analysis does not include the economic benefits and costs of utilization of the slurry wastes as fertilizer. This is certainly an option which must be addressed in a more systemic look at the farm as a semi-autonomous production unit.

TABLE 5

Cost analysis 30 kW generator

Average cost pricing (ACP) and marginal cost pricing (MCP) with elasticities of 0.0 and –0.14.

	Methane farm			Conventional farm			Difference methane—conventional		
	ACP	MCP		ACP	MCP		ACP	MCP	
		0.0	–0.14		0.0	–0.14		0.0	–0.14
Farmer									
Incremental capital expense	3553	3553	3553						
Electric bill	0	0	0	2093	1991	1864			
Total expenses to farmer for electricity	3553	3553	3553	2093	1991	1864			
Additional cost to methane farmer							1460	1562	1689
Utility									
Short-run costs	0	0	0	1392	1392	1305			
Long-run costs	0	0	0	1507	1507	1507			
Total costs	0	0	0	2899	2899	2812			
Revenues from customers bills	0	0	0	2093	1991	1864			
Balance to utility (costs—revenues)	0	0	0	806	908	948			
Additional cost to utility of serving methane farm over conventional							–806	–908	–948
Total additional costs of serving methane over conventional (total of utility and farm)							654	654	741

TABLE 6

Cost analysis 30 kW generator and power sales

Average cost pricing (ACP) and marginal cost pricing (MCP) with elasticities of 0.0 and −0.14.

	Methane farm			Conventional farm			Difference methane—conventional		
	ACP	MCP		ACP	MCP		ACP	MCP	
		0.0	−0.14		0.0	−0.14		0.0	−0.14
Farmer									
Incremental capital expense	3553	3553	3553						
Electric bill	−780	−1150	−1150	2093	1991	1864			
Total expenses to farmer for electricity	2772	2403	2403	2093	1991	1864			
Additional cost to methane farmer							680	412	539
Utility									
Short-run costs	−515	−620	−620	1392	1392	1305			
Long-run costs	−212	−316	−316	1507	1507	1507			
Total costs	−726	−936	−936	2899	2899	2812			
Revenues from customers bills	−780	−1150	−1150	2093	1991	1864			
Balance to utility (costs—revenues)	54	214	214	806	908	948			
Additional costs to utility of serving methane farm over conventional							−752	−694	−734
Total additional costs of serving methane over conventional (total of utility and farm)							− 72	−282	−195

TABLE 7

Summary cost analysis

Three methane generation scenarios. Average cost pricing (ACP) and marginal cost pricing (MCP) with elasticities of 0.0 and −0.14.

	12.5 kW			30 kW			30 kW + sales		
	ACP	MCP		ACP	MCP		ACP	MCP	
		0.0	−0.14		0.0	−0.14		0.0	−0.14
Additional cost to farmer of methane generation	1017	1198	1272	1460	1562	1689	680	412	539
Additional costs to utility of methane generation	−247	−455	−475	−806	−908	−948	−752	−674	−734
Total additional costs of methane to both utility and farmer	743	743	797	654	654	741	−72	−282	−195

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