Environmental Impact of Residential Fuel Switching

Edward M. Weaver and Patricia Herman, Barakat and Chamberlin, Inc.

Regulators and utilities are investigating fuel switching programs to supplement more traditional electric DSM strategies. The environmental impact of fuel switching depends on numerous factors, including fuel mix, equipment efficiency, and load shape at the end use; fuel mix, technology, and pollution control at utility generators; and societal cost of different pollutants.

This paper uses a case study of a New England utility to quantify these factors. The paper quantifies air emissions of residential space and water heating equipment for a number of fuels, quantifies emission reductions from deferred generation, and values the societal costs imposed by residual emissions. Generation emissions are quantified with a dispatch simulation model to capture load shape and site-specific generation parameters. Societal costs are quantified by comparing values adopted by various regulatory commissions.

This case study shows that the environmental impacts of fuel switching programs are highly uncertain and likely to be case specific. Important factors driving the overall emission impacts include the mix of end-use and generation fuels as well as the use of site-specific emissions coefficients for generation sources. Of secondary importance are the values placed on the different emissions.

Introduction

One of the most powerful arguments for energy conservation is the protection of our resources and our environment. Over the past five years, more and more states have formalized this belief by allowing, and in some cases, requiring, the inclusion of environmental benefits in the selection and evaluation of conservation programs. In almost all cases, the environmental benefits of a program are considered to be reductions in the negative environmental impacts (mainly air emissions) of electricity generation. When conservation is focused on electricity reduction alone, this definition is not necessarily a problem. (There are negative environmental impacts to some conservation measures, but they to tend to be small.) But more utilities are considering fuel switching (promoting the use of another fuel as a substitute for electric use) as a way to reduce their electric load.

Few studies have addressed the environmental impacts of fuel switching, and those that do tend to focus only on the benefits from the reduction in electricity generation. This paper demonstrates that the environmental impacts of fuel switching are not entirely straightforward. Appliances that burn fossil fuels--even efficient appliances--have negative environmental impacts that cannot be ignored. And these increased emissions may actually override the benefits from the reduction in electric generation. This disturbing result is made even more troublesome by the fact that customers' appliances are not under the same scrutiny and regulation for emissions controls as is utility generation.

This paper calculates the changes in air emissions from two proposed fuel switching programs at a rural New England electric utility. It first calculates emissions changes in physical units (tons) by emission. It then places the changes in common dollar units using societal emissions costs adopted by various state regulatory commissions.

The New England electric utility represented in this case study undertook a collaborative process to design a number of potential DSM programs for its customers. Two of these programs involved the substitution of existing electric equipment with fossil- and wood-fueled alternatives. One program targeted existing electric water heat; the other targeted existing electric space heat. For analysis purposes, each program targeted one megawatt of load reduction.

This rural service territory has no access to utility natural gas. Almost 70% of its customers use electric water heat, and over 10% use electric space heat. Oil is the predominant alternative fuel in use in the service territory, although propane and wood are also widespread, and some customers use kerosene wall heaters.

The utility relies on hydroelectric units for most of its electric generation needs, although fossil units are on the margin (and therefore deferred through load reductions) in most hours. Fossil units include on-system diesel engines used sparingly for peaking needs, as well as coal and residual oil units located on neighboring New England systems. In addition, the utility's resource plan calls for the construction of two natural gas units to offset both increasing demand and retiring generation units. The new units include a simple-cycle combustion turbine and a combined-cycle combustion turbine.

Research Approach

The research approach included the following five steps:

1. Estimate changes in fuel consumption;
2. Estimate emission coefficients;
3. Estimate change in emissions;
4. Estimate societal cost of individual emissions; and
5. Estimate societal cost of program emissions.

For each program (water heat and space heat), changes in fuel consumption over the analysis period were estimated. Changes included increases at the end use as well as decreases at the generation level. Emissions coefficients, expressed in pounds of emission per million Btu (MMBtu) of fuel consumed, were estimated for each fuel and technology for seven different emissions. Changes in emissions over the analysis period were then calculated by multiplying changes in fuel use by emission coefficients and summing across technologies and fuels. Net emissions increased or decreased depending on program and mission. A range of societal costs for individual emissions was developed using values approved by four different state regulatory commissions. Finally, the net cost or benefit of the fuel switching programs was calculated by multiplying changes in emissions by societal emission costs and summing across emissions.

Change in Fuel Consumption

Tables 1 and 2 present the change in fuel consumption over the 30-year analysis period at the end-use and generation levels, respectively. Each table displays changes by fuel and technology for each program. Table 1 displays values both in annual fuel quantities (gallons or cords) and in MMBtu, while Table 2 displays values both in avoided output (GWh) and avoided fuel use (MMBtu). Note that Table 2 does not display the hydroelectric generation avoided by the programs.

Increases in end-use fuel use were developed by the members of the collaborative process. For each program, the collaborative stratified the target market into four consumption groups (low, moderate, high, and very high). For each group, the collaborative considered the mix of existing space heating and water heating configurations, the life-cycle costs of alternative replacement systems, and customer preferences to arrive at an appropriate mix of replacement systems. Replacement water heat systems considered included stand-alone propane and oil, integrated propane and oil (integrated with existing boilers), and wood preheaters. Replacement space heat systems considered included oil and propane furnaces, oil and propane boilers, wood stoves, and kerosene and propane wall heaters.

All fossil-fuel systems considered were high-efficiency units. Water heater energy factors ranged from .62 to .65

Table 1. Increased End-Use Energy Consumption

		Annual Energy Use (Units)			30-Year Energy Use (MMBtu)	
	Heat Content (MMBtu/unit)	Units	Water Heaters	Space Heaters	Water Heaters	Space Heaters
Propane	92	1000 gal	5.060	4.723	13,966	13,035
Kerosene	137	1000 gal	0	19.640	0	80,720
#2 Oil	138	1000 gal	125.780	39.940	520,729	165,352
Wood	23	cord	233	78	160,770	53,820
Total					**695,465**	**312,927**

Table 2. 30-Year Avoided Generation Energy Requirement					
		Avoided Energy (GWh)		Avoided Energy (MMBtu)	
	Heat Rate (Btu/kWh)	Water Heat Program	Space Heat Program	Water Heat Program	Space Heat Program
Purchases	10000	-0.44	0.04	(4,400)	400
Coal 1	9990	1.71	0.27	17,083	2,697
Coal 2	11082	1.93	0	21,388	0
Oil 1	9373	2.97	1.28	27,838	11,997
Oil 2	10683	10.06	7.38	107,471	78,841
Diesel 1	9777	1.23	0.92	12,026	8,995
Gas CT	11823	37.9	21.54	448,092	254,667
Gas CC	9313	24.47	14.75	227,889	137,367
Total		**79.83**	**46.18**	**857,386**	**494,964**

for stand-alone units and up to .75 for integrated systems. Space heat seasonal efficiencies ranged from .80 to .85 for furnaces, from .82 to .87 for boilers, and from .80 to .87 for wall heaters.

Decreases in generation fuel use were then developed by modeling changes to the utility generation system through the use of a production costing model. Load decrements specific to each program were developed using available end use load data. The utility system was then simulated with and without each program decrement, with construction and plant dispatch schedules adjusted to minimize system costs over the analysis period. The production cost model then calculated the reduced output and fuel consumption for each plant over the analysis period.

Emissions Coefficients

Tables 3 and 4 present the emissions coefficients by fuel, technology, and emission for end-use and generation technologies, respectively. The tables display coefficients for sulfur oxides (SO_X), nitrogen oxides (NO_X), carbon dioxide (CO_2), total suspended particulates (TSP), carbon monoxide (CO), volatile organic compounds (VOC), and methane (CH_4).

Table 3 presents end-use coefficients in terms of pounds per quantity of fuel consumed (gallons or cords) as well as in pounds per MMBtu of fuel consumed. The fuel heat contents displayed in Table 1 were used to make this conversion. Coefficients are not assumed to vary between space and water heating systems.

End-use coefficients for all emissions except CO_2 were derived primarily from the U.S. Environmental Protection Agency's AP-42 data (USEPA 1990). Kerosene coefficients were developed from USEPA's #2 oil coefficients on an equivalent Btu basis. Wood coefficients assume Phase II catalytic stoves and a wood density of 1.5 tons per cord. Sulfur oxide coefficients assume .16 grams of sulfur per ccf for propane, 0.10% sulfur by weight for kerosene, and 0.55% sulfur by weight for #2 oil. Coefficients for CO_2 were derived from the density and carbon content of each fuel. Carbon combustion efficiencies of 99% and 95% were assumed for fossil and wood systems, respectively.

Table 4 presents generation coefficients in terms of pound per MMBtu of fuel consumed. Where available, generation coefficients represent the actual emissions profiles of specific plants included in the utility generation mix. Where plant-specific data were unavailable, more general sources were used (Bernow 1990; CEC 1990a; USEPA 1990). Profiles for the new combustion turbines are representative of new gas generation recently proposed in New England (Tellus Institute 1990).

Change in Emissions

Table 5 and 6 present the change in emissions over the 30-year analysis period at the end-use and generation levels, respectively. Each table displays changes by fuel and technology for each program. Changes in emissions were calculated as simply the product of change in fuel use and emissions coefficients. Figures 1 and 2 show in graphical form the magnitude of the changes in emissions

Table 3. End-Use Emission Coefficients

	Fuel Quality Units	Air Emissions SOx	NOx	CO2	TSP	CO	VOC	CH4
lb/unit								
Propane	1000 gal	0.014	8.8	12,637	0.265	1.8	0.710	0.24
Kerosene	1000 gal	14	17.9	21,557	2.5	5.0	2.475	1.77
#2 Oil	1000 gal	79	18.0	22,584	2.5	5.0	2.493	1.78
Wood	cord	0.6	3.0	5,535	19.5	117	64.5	39
lb/MMBtu								
Propane	1000 gal	0.0002	0.0957	137	0.0029	0.0196	0.0077	0.0026
Kerosene	1000 gal	0.1048	0.1304	157	0.0181	0.0362	0.0181	0.0129
#2 Oil	1000 gal	0.5723	0.1304	164	0.0181	0.0362	0.0181	0.0129
Wood	cord	0.0261	0.1304	241	0.8478	5.0870	2.8043	1.6957

Table 4. Generation Emission Coefficients

	Air Emission SOx	NOx	CO2	TSP	CO	VOC	CH4
lb/MMBtu							
Purchases	1.492	0.673	195	0.146	0.029	0.004	0.002
Coal 1	2.287	1.401	220	0.240	0.024	0.0028	0.0012
Coal 2	1.029	0.746	220	0.240	0.024	0.0028	0.0012
Oil 1	0.924	0.277	170	0.004	0.033	0.0051	0.0019
Oil 2	1.727	0.269	170	0.100	0.033	0.0051	0.0019
Diesel 1	0.414	3.448	164	0.345	0.897	0.0966	0.0069
Gas CT	0.0006	0.036	118	0.001	0.021	0.0330	0.0019
Gas CC	0.0006	0.036	118	0.001	0.021	0.0330	0.0019

for each program. Table 7 displays the net change in emissions. Positive values in Table 7 represent increased emissions as a result of the fuel switching activity; negative values represent decreased emissions.

Societal Cost of Individual Emissions

A number of regulatory commissions, utilities, and research organizations have attempted to estimate the societal cost that increased emissions place on society (Koomey 1989; NYPSC 1991). Estimates vary considerably--both in the number of emissions covered as well as the magnitude of values employed. Table 8 displays values from four different state regulatory commissions (Nevada PSC 1991; Mass DPU 1990; CEC 1990b; NYPSC 1989). Since the commission orders present values using different bases for expressing dollars, Table 8 also displays values in common units of 1990 dollars. Values were escalated to 1990 dollars at 5% per year.

Table 5. Increased End Use Emissions (tons)

	Air Emission						
	SOx	NOx	CO2	TSP	CO	VOC	CH4
Water Heat Program							
Propane	0	1	959	0	0	0	0
Kerosene	0	0	0	0	0	0	0
#2 Oil	149	34	42,610	5	9	5	3
Wood	2	10	19,343	68	409	225	136
Total	**151**	**45**	**62,912**	**73**	**418**	**230**	**140**
Space Heat Program							
Propane	0	1	895	0	0	0	0
Kerosene	4	5	6,351	1	1	1	1
#2 Oil	47	11	13,530	1	3	1	1
Wood	1	4	6,475	23	137	75	46
Total	**52**	**20**	**27,252**	**25**	**141**	**78**	**47**

Table 6. Avoided Generation Emissions (tons)

	Air Emission						
	SOx	NOx	CO2	TSP	CO	VOC	CH4
Water Heat Program							
Purchases	(3)	(1)	(429)	(0)	(0)	(0)	(0)
Coal 1	20	12	1,879	2	0	0	0
Coal 2	11	8	2,353	3	0	0	0
Oil 1	13	4	2,366	0	0	0	0
Oil 2	93	14	9,135	5	2	0	0
Diesel 1	2	21	986	2	5	1	0
Gas CT	0	8	26,437	0	5	7	0
Gas CC	0	4	13,445	0	2	4	0
Total	**136**	**70**	**56,173**	**12**	**15**	**12**	**1**
Space Heat Program							
Purchases	0	0	39	0	0	0	0
Coal 1	3	2	297	0	0	0	0
Coal 2	0	0	0	0	0	0	0
Oil 1	6	2	1,020	0	0	0	0
Oil 2	68	11	6,701	4	1	0	0
Diesel 1	2	16	738	2	4	0	0
Gas CT	0	5	15,025	0	3	4	0
Gas CC	0	2	8,105	0	1	2	0
Total	**79**	**37**	**31,925**	**6**	**10**	**7**	**0**

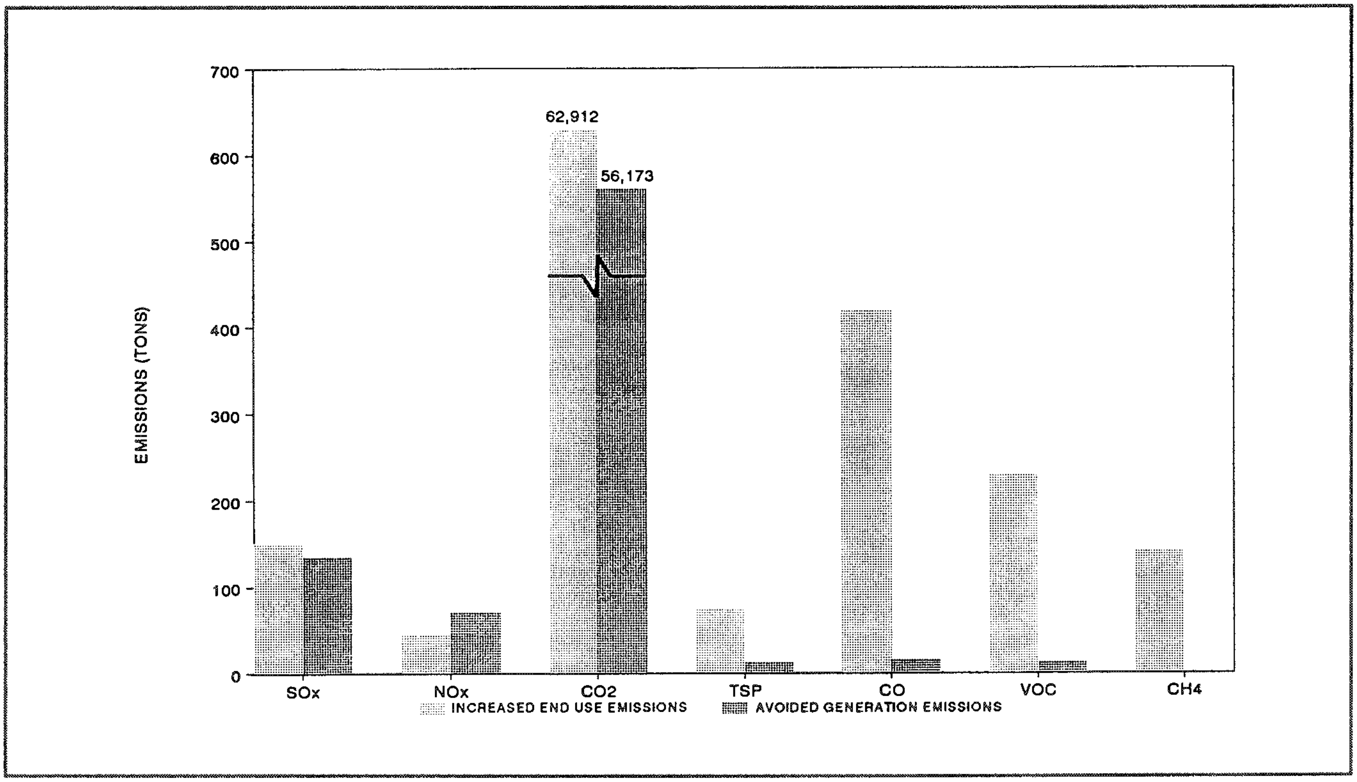

Figure 1. Increased End Use Emissions vs. Avoided Generation Emissions; Water Heat Program

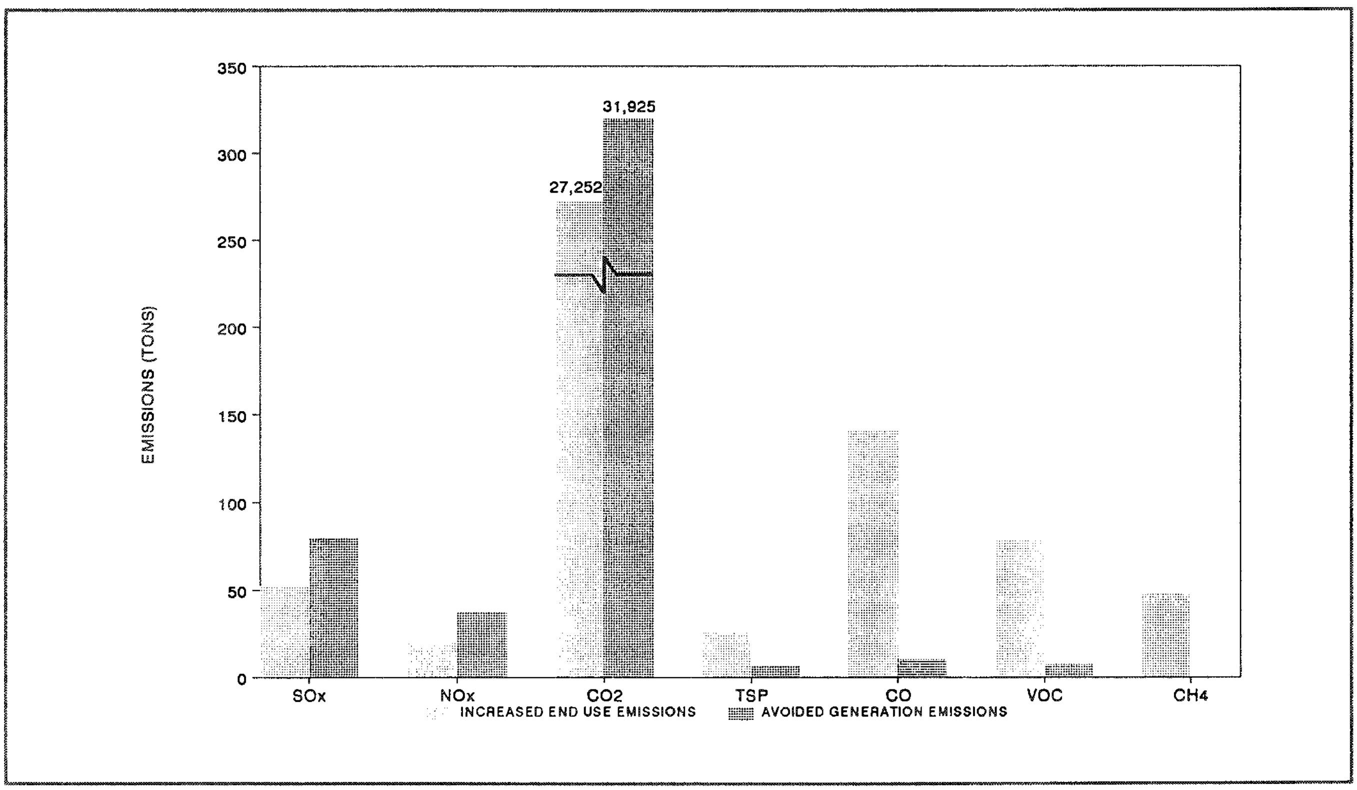

Figure 2. Increased End Use Emissions vs. Avoided Generation Emissions; Space Heat Program

Table 7. Net Emission Impact (tons)

	Air Emission						
	SOx	NOx	CO2	TSP	CO	VOC	CH4
Water Heat Program							
End-Use Fuel	151	45	62,912	73	418	230	140
Avoided Generation	136	70	56,173	12	15	12	1
Net Increase (Decrease)	**16**	**(25)**	**6,739**	**61**	**403**	**218**	**139**
Space Heat Program							
End-Use Fuel	52	20	27,252	25	141	78	47
Avoided Generation	79	37	31,925	6	10	7	0
Net Increase (Decrease)	**(27)**	**(17)**	**(4,673)**	**19**	**132**	**71**	**47**

Table 8. Societal Cost of Individual Emissions ($/ton)

	Air Emission							
	Year Dollars	SOx	NOx	CO2	TSP	CO	VOC	CH4
Current Year Dollars								
Nevada	1990	$1,560	$6,800	$22	$4,180	$920	$1,180	$220
Massachusetts	1989	$1,500	$6,500	$22	$4,000	$870	$5,300	$220
New York	1989	$1,880	$960	$3	$2,020			
California								
SCAQMD	1987	$11,500	$11,600	$7	$7,800		$3,300	
Out-of-state	1987	$1,000	$2,700	$7	$800		$300	
1990 Dollars								
Nevada	1990	$1,560	$6,800	$22	$4,180	$920	$1,180	$220
Massachusetts	1990	$1,575	$6,825	$23	$4,200	$914	$5,565	$231
New York	1990	$1,974	$1,008	$3	$2,121			
California								
SCAQMD	1990	$13,313	$13,428	$8	$9,029		$3,820	
Out-of-state	1990	$1,158	$3,126	$8	$926		$347	

Note that the Massachusetts and Nevada commissions have placed values on all seven emissions, while New York has valued only four emissions (SO_X, NO_X, CO_2, and TSP) and California has valued only five emissions (SO_X, NO_X, CO_2, TSP, and VOC). Note also that California values out-of-state emissions significantly lower than emissions in the South Coast Air Quality Management District (SCAQMD).[1]

Societal Cost of Program Emissions

Table 9 displays the net societal cost of the emissions impact of each program. Costs and benefits for each emission are calculated as the product of net emissions impact and societal emissions cost. The net societal cost or benefit of each program is then calculated by summing across emissions. For the Nevada and Massachusetts values, costs are summed across all seven emissions, as well as across the four emissions that have been valued by all states. For the New York and California values, costs are summed only across the four common emissions.

By applying emissions values to the net emissions impact over the entire analysis period, this analysis ignores the pattern of emission increases and decreases over time. An alternative approach would value annual changes in emissions and then calculate the net present value of emissions costs over the entire analysis period using a societal discount rate. The approach here attempted merely to illustrate the relative value the different commissions have placed on the individual emissions. Since the spread among emission values is already fairly significant, the complexity of the annual approach would likely add little to the analysis. In addition, some analysts have suggested that a 0% real discount rate is appropriate for valuing environmental impacts. If a 0% real discount rate were applied to annual emissions costs, the values in Table 9 would result.

By applying emission values adopted by various states, this analysis also ignores any regional-specific environmental costs. That is, to some extent, the states take into account local conditions in placing values on the cost of increased air emissions. For example, the cost of increased emissions might be higher in areas that currently do not meet USEPA standards. The State of California acknowledged such an effect when it valued out-of-state emissions at levels ranging from 75% to 90% below SCAQMD emissions.

Discussion

Net Environmental Impact of Programs

The emissions impacts of fuel switching on this system are far from clear, because each program increases some emissions and decreases others. The water heat program is more likely to produce a negative overall impact, because it increases six emissions while only slightly decreasing NO_X emissions. This is borne out by the societal costs, which increase for all sets of commission values and for both sets of emissions considered.

The space heat program produces more conflicting results. It decreases three key emissions (SO_X, NO_X, and CO_2) while increasing the other four emissions. The societal costing helps to some extent by placing the emissions impacts in common dollar units. However, the results of the societal costing varies dramatically depending on the number of emissions considered. Across the four common emissions, the space heat program produces net benefits regardless of the emission values used. However, in both cases considering the additional three emissions, the program produces net environmental costs.

Variation of Emission Values by Commission

For the programs considered here, the choice of values developed by the different commissions has less of an impact than the choice of which emissions to value. All states value the water heat program as producing net environmental costs, regardless of whether four or seven emissions are considered. If only four emissions are considered, all states value the space heat program as providing net environmental benefits, while both states that consider all seven emissions value the program as producing net environmental costs.

The magnitude of environmental costs and benefits vary considerably by state. For the water heat program, if four emissions are considered, the net societal costs vary by a factor of around nine across the five estimates. The California SCAQMD values produce the highest costs; the California out-of-state values produce the lowest costs. The Nevada and Massachusetts values produce very similar costs across the four common emissions. However, when considering all seven emissions, the Massachusetts values produce societal costs almost twice as high as the Nevada values. A similar pattern emerges for the space heat program, although the New York values produce the lowest societal cost in this case. In addition, across the seven emissions, the Massachusetts values produce societal costs 10 times higher than the Nevada values.

Generation Mix

The mix of avoided generation is clearly a determining factor in the overall emissions balance. Approximately 80% of the generation fuel avoided by the programs (expressed in MMBtu) come from the natural gas units. That is, the programs effectively displace the construction of new, relatively efficient, and relatively clean generation sources. The petroleum- and wood-fired end-use systems have a difficult time competing with the emissions profiles of these units.

Table 9. Societal Cost (Benefit) of Fuel Switching Program ($000)

	Air Emission							Four Emission	Seven Emission
	SOx	NOx	CO2	TSP	CO	VOC	CH4	Total	Total
Water Heat Program									
Nevada	$24	($167)	$148	$254	$371	$257	$31	$259	$918
Massachusetts	$23	($160)	$148	$243	$351	$1,156	$31	$255	$1,792
New York	$29	($24)	$20	$123				$149	
California									
SCAQMD	$178	($285)	$47	$474				$414	
Out-of-state	$16	($66)	$47	$49				$45	
Space Heat Program									
Nevada	($42)	($113)	($103)	$79	$121	$83	$10	($178)	$36
Massachusetts	($42)	($114)	($108)	$80	$120	$393	$11	($184)	$340
New York	($53)	($17)	($15)	$40				($44)	
California									
SCAQMD	($356)	($224)	($38)	$172				($446)	
Out-of-state	($31)	($52)	($38)	$18				($103)	

Conclusion

This case study shows that the environmental impacts of fuel switching programs are highly uncertain and likely to be case specific. Important factors driving the overall emissions impacts include:

- The mix of end-use fuels (note that this example is a rural utility with an end-use fuel mix of propane, kerosene, oil, and wood);
- The mix of generation fuels (the fuels used by the generation resources at the margin); and
- The use of site-specific emissions coefficients for generation resources (the emissions coefficients for the actual plants).

Of secondary importance are the values placed on the different emissions.

This paper concludes that a general statement cannot be made regarding the environmental impacts of fuel switching programs. Each fuel switching program must be evaluated separately given site-specific data.

Endnotes

1. The California Energy Commission (CEC), in its current review of emission values, is surveying surrounding states to get more accurate estimates of out-of-state emission costs.

References

Bernow, S., B. Biewald, and D. Marron. 1990. *Full Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation.* Presented at NARUC Conference on Environmental Externalities. Jackson Hole, Wyoming, October 1-3.

California Energy Commission (CEC). 1990a. *1988 Inventory of Greenhouse Gas Emissions, Final Staff Report*. October.

_______. 1990b. *Electricity Report 1990.* October.

Koomey, J. 1990. *Comparative Analysis of Monetary Estimates of External Environmental Costs Associated with Combustion of Fossil Fuels.* Lawrence Berkeley Laboratory Report LBL-28313, July.

Massachusetts Department of Public Utilities (Mass DPU). 1990. Order in Docket DPU89-239, August 31.

Nevada Public Service Commission (Nevada PSC). 1991. Order in Docket 89-752, January 22.

New York Public Service Commission (NYPSC). 1989. Order Issuing a Final Environmental Impact Statement, Case 88-E-246, July 19.

_______.1991. *Draft New York State Energy Plan, 1991 Biennial Update*, Volume III, *Energy and Environmental Taxes Issue Paper*.

Tellus Institute. 1990. *Evaluation of Repowering the Manchester Street Station*. A Report to Rhode Island Division of Public Utilities and Carriers, Rhode Island Division of Statewide Planning, and Rhode Island Governor's Office of Housing, Energy and Intergovernmental Relations, May.

United States Environmental Protection Agency (USEPA). 1990. *Compilation of Air Pollutant Emission Factors*, Volume I: *Stationary Point and Area Sources, Supplement C, AP-42,* Fourth Edition, September.