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Minnesota's Commercial Alternative Energy Industries

Production, Policies and Local Economies

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Seeking solutions for Greater Minnesota's future

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Report Summary

A confluence of economic and political forces is leading to renewed attention to the potential for Minnesota to increase its share of homegrown energy. Alternative energy industries, the argument goes, should receive public support because they generate a pattern of spending and outputs that are in some sense better than the patterns of traditional energy industries. Is that true? How much potential is there, really? And what would such an increase mean for the state's economy?

To properly address these questions, we need an analytic approach that permits us to array dissimilar industries on the same framework, making assumptions and key parameters transparent, so that we can examine cross-industry economic linkages and conduct a forward-looking analysis of these industries.

Our framework, at its core, is a set of individual energy production industry budgets that track the transformation of feedstocks (corn, garbage, wind, etc.) into energy, jobs, and spending. We use these budgets to estimate key outputs for each of the major alternative energy industries in the state: two fuels — ethanol and biodiesel — and four electricity generation systems — from wind, garbage, landfill gas, and waste wood. This table shows our statewide summary estimates for the six industries. In the report, we provide details at the regional and the plant level.

As the charts below highlight, ethanol is the major player in these industries, accounting for two-thirds of the associated jobs and local spending. Wind power accounts for a substantial portion of the energy production total, but it generates comparatively little local economic impact.

To help support current production and to stimulate additional capacity in these industries, Minnesota and the federal government have crafted a mix of policies that includes incentives, disincentives, research, and education. Having a mix is a reasonable strategy, but we think that the total of these activities is too small and that the proportions of the ingredients are skewed because the current mix relies too much on the government singling out particular resources or technologies for special treatment.

We think it would be better if the government spent its scarce alternative energy investments on improving general market conditions and increasing the store of knowledge. To that end, the following additions to the policy mix might improve the potential for alternative energy industries to improve local economic conditions.

1. *Establish a consistent reporting and tracking system.*

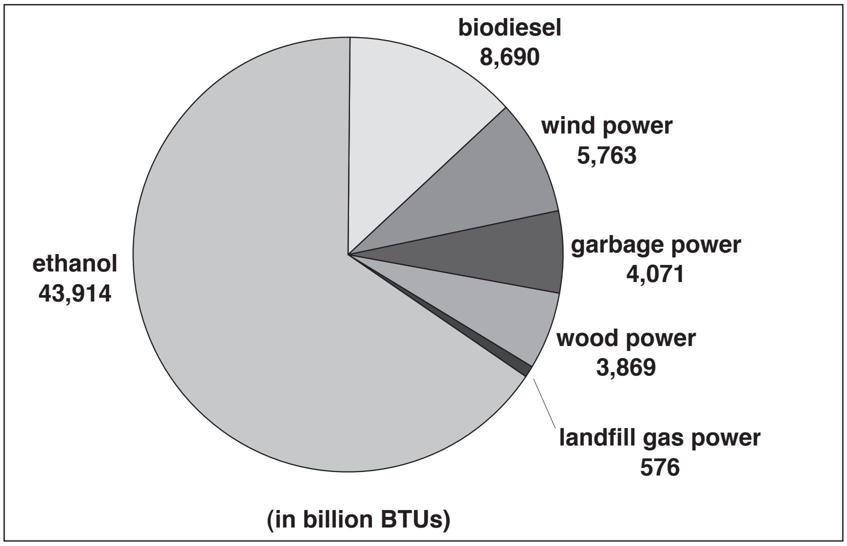
2. *Reduce uncertainty in production and marketing.*

3. *Continue to support research into new technologies that increase local development.*

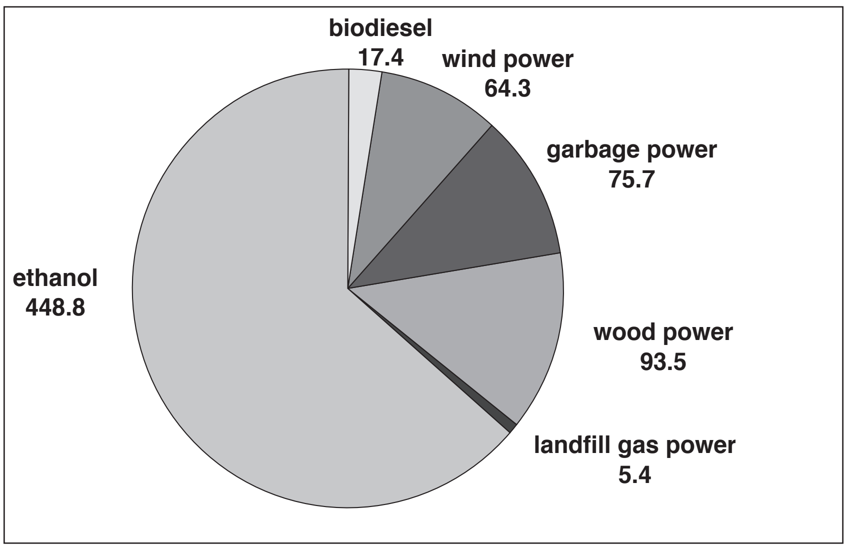
4. *Create conditions for creative energy markets.*

Our general conclusion: Minnesota's appetite for energy is large and the output from even an expanded alternative energy system will remain small in comparison — except in a few submarkets. But the local economic gains from such expansion might make it worth trying to bring it about nevertheless.

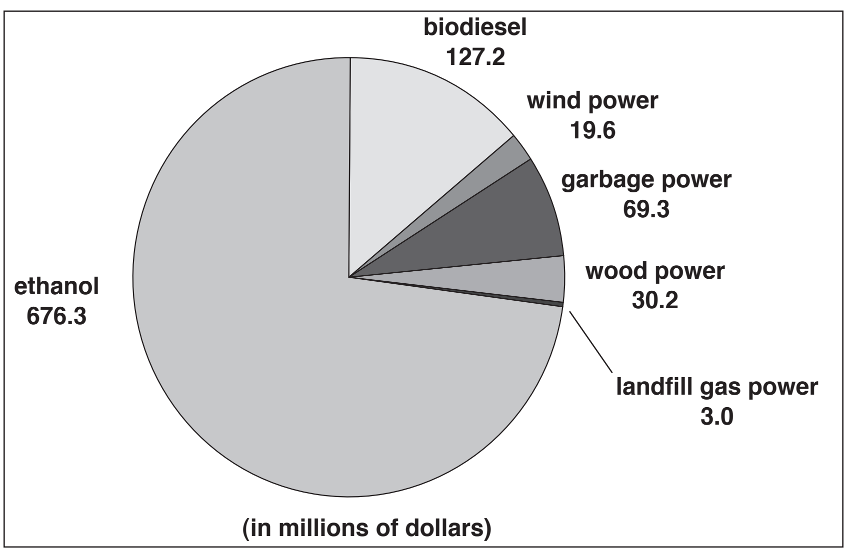
Alternative energy in Minnesota



Estimated energy produced by Minnesota alternative energy industries, billion Btu, 2005



Estimated local jobs generated by Minnesota alternative energy industries, 2005



Estimated local spending generated by Minnesota alternative energy industries, 2005

Introduction

Minnesotans are thinking more about alternative energy these days for three major reasons. First, and most visibly, energy prices are climbing, especially for petroleum-based fuels, both because of shortfalls in supply and constrictions in distribution networks. Could alternative energy industries boost our supplies and so lower prices? Second, concerns about global warming have focused attention on the large emissions of CO_2, a greenhouse gas, from our production and use of energy. Can alternative technologies and feedstocks give us the energy we need without releasing as much CO_2 (along with conventional pollutants like SO_2)? Finally, Minnesota, like the rest of America, remains locked in a depressed economy. Could more in-state energy production boost local economies by creating new jobs and spending?

All three of these forces lead to renewed attention to the potential for Minnesota to increase its share of home-grown energy. But how much potential is there, really? And what would such an increase mean for the state's economy?

Our general conclusion: Minnesota's appetite for energy is large and the output from even an expanded alternative energy system will remain small in comparison — except in a few submarkets. But the local economic gains from such expansion might make it worth trying to bring it about nevertheless.

Scope

In this report, we provide a framework for examining some of these questions. Alternative energy industries, the argument goes, should receive public financial assistance because they generate a pattern of spending and outputs that are in some sense better than the patterns of traditional energy industries. Using a new cost and production accounting framework, we will describe the current set of industries, estimate their levels of production and economic impact, and explore some of the implications of changes in the economic and policy environment within which these industries operate.

We confine our examination to "commercial" energy firms, those that sell electricity through the grid or ship fuels to downstream markets. Our definition of "alternative" is confined to ethanol and biodiesel production among the fuels and to electricity generated by wind, landfill gas, wood, and municipal solid waste facilities. We do not look at coal, nuclear, solar, hydro, or natural gas electric power generation, nor do we consider petroleum-based fuels. We do not measure the effects of conservation either by residential or commercial consumers, either through reducing demand for energy or through substituting in-plant generating capacity for purchased energy. Finally, we do not examine the environmental or social effects of the examined industries.

None of the estimates presented here are suitable for use as financial investment projections, nor are they meant to precisely measure the effects on local economies of industry expansion that, as yet, remains hypothetical.

Minnesota's commercial energy production sector

The most recent and consistent state-by-state data for U.S. energy consumption and production is from the Energy Information Administration for 2003. Both nationally and in Minnesota, alternative energy (however liberally defined) constitutes only a small portion of energy production or consumption. For example, less than 3 percent of Minnesota's 2003 production of electric power was from alternative energy sources. Coal-fired and nuclear generating plants produced the vast majority of the power from conventional sources (Figure 1), while the bulk of the alternative production was from wind power and from the burning of municipal solid waste (Figure 2). Minnesota generates most of its own electricity, but the bulk of the feedstocks (coal, oil, natural gas, uranium) are imported from other states or nations.

For fuels (most of which are used for transportation), locally produced ethanol amounted to less than 3 percent of total fuels used (Figure 3). (Note that the data in the fuels table are for consumption, not production.) There was no biodiesel produced in the state in 2003, the most recent year for which fuels data is available, and the ethanol consumption was completely met by in-state production.

Figure 1: Minnesota electric power production from conventional sources, 2003

	Fuel units	Total fuel	Net production (MWh)
Bituminous coal	short tons	1,102,739	656,255
Black Liquor	short tons	701,239	168,993
Distillate fuel oil	barrels	225,360	96,285
Natural Gas	thousand cubic feet	27,490,301	2,068,349
Nuclear	N/A	—	13,413,828
Petroleum Coke	short tons	262,236	737,645
Residual fuel oil	barrels	90,563	29,105
Sub-bituminous coal	short tons	21,166,419	34,918,927
Hydroelectric	N/A	—	960,965
TOTAL		**51,038,857**	**53,050,352**

Source: US Energy Information Administration

Figure 2: Minnesota electric power production from non-conventional sources, 2003

	Fuel consumption units	Total fuel consumption	Net power production (MWh)
Landfill gas	thousand cubic feet	2,589,713	97,776
Municipal Solid Waste	short tons	1,005,414	605,237
Purchased Steam	N/A	—	38,650
Sludge Waste	short tons	35,218	6,531
Wood waste liquids	barrels	189,217	71,319
Wood waste solids	Short tons	491,596	159,288
Wind	N/A	—	884,021
TOTAL		**4,311,158**	**1,862,822**

Source: US Energy Information Administration

Figure 3: Minnesota motor fuel use, 2000

	Consumption (million gallons)
Ethanol	260
Total petroleum	5,670
TOTAL	5,930

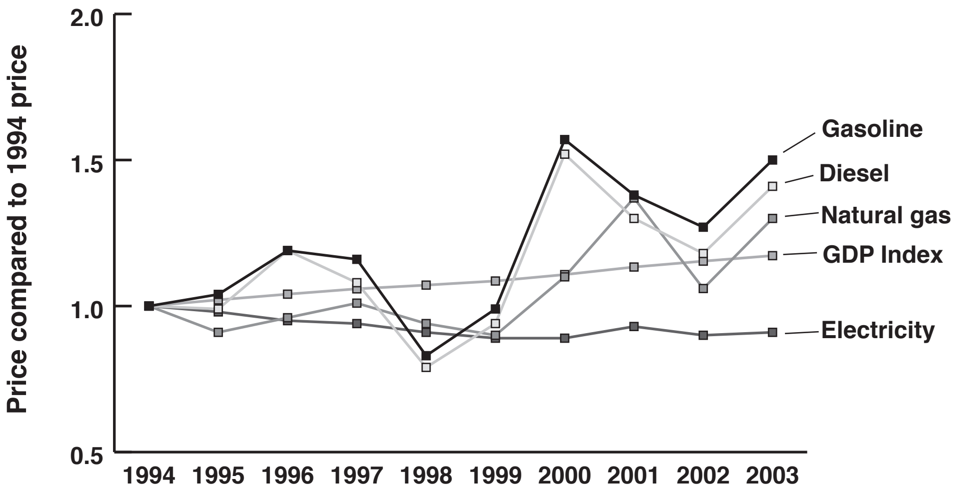
Source: Minnesota Department of Commerce

In all the other tables in this report, we rely upon our own estimates of energy production. Building as we do from individual plant reports, our numbers will not completely match in quantity or in relative size those shown in the figure, because the EIA data, for reasons of national reporting consistency, includes production that is not attributed to specific locations. Unless otherwise noted, all production and cost estimates are those of the authors.

Energy price trends

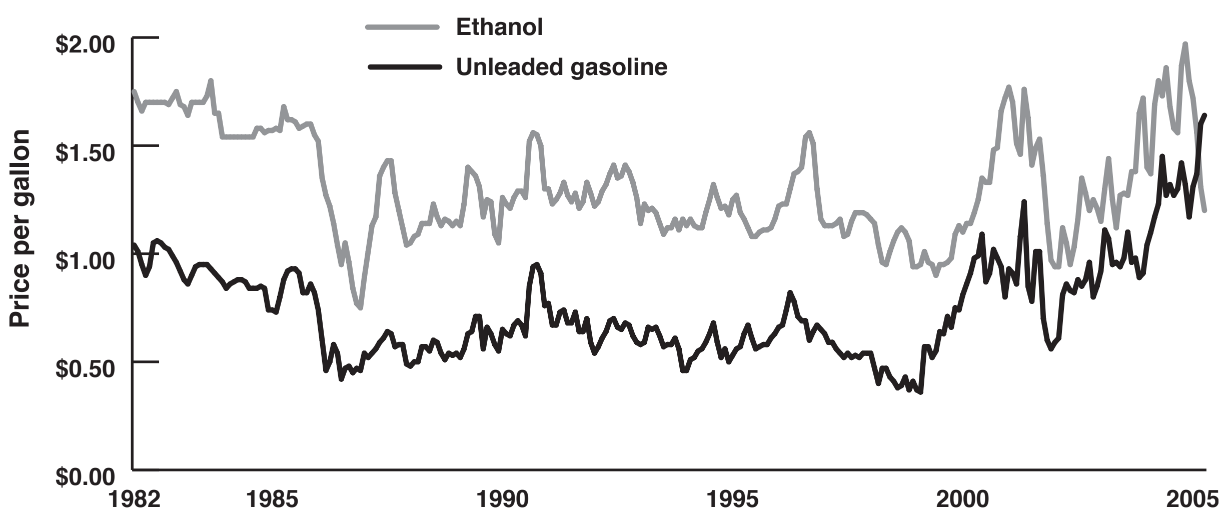
Minnesota's alternative energy industries, as defined in this paper, produce three energy products: electricity, ethanol, or biodiesel. In each case, the state's industries are small relative to the total market. We can confidently say that for now and in the foreseeable future, nothing Minnesota does in these markets will affect the price that alternative energy producers receive. Figures 4 and 5 show average price histories for electricity and ethanol. (Biodiesel price series are not publicly available.)

Figure 4: Indexed U.S. energy prices, 1994-2003



Source: Eidman, 2005

Figure 5: Ethanol (gray line) and unleaded gasoline (black line) wholesale prices



Source: Omaha average rack prices; Nebraska Energy Office, 2005

For electricity, the key point is one of stability: electricity prices were largely unchanged over the period shown here, partially due their being highly regulated. Stability is not seen in the price histories for ethanol, however. The rack price (roughly, the wholesale price) of ethanol clearly parallels that of gasoline, but the gap between the two has narrowed appreciably in recent years. Indeed, a recent dramatic drop in the price of ethanol (due to market concerns that the industry was over-producing), coupled with increases in the price of gasoline (due to higher oil prices), resulted in a reversal of traditional price relationships for these fuels. (This reversal lasted only a few months, however.) Ethanol futures contracts are now selling at the Chicago Board of Trade. As the market for these contracts matures, their prices will be the best single reflection of the economic state of the ethanol industry.

Analysis approach

We want to estimate how Minnesota's alternative energy industries affect local economies and how changing economic conditions might affect their financial prospects. There exist many economic studies of particular alternative energy technologies, especially technologies that are not yet in the ground. There are many reports on what might happen if everything breaks properly. There are far fewer on what actually did happen when new industries came into being. And there exist essentially none on the actual financial performance of these industries (other than the obvious observation that if a particular plant is still producing, it must be making money). These industry studies tend to be quite detailed and at the same time quite assumption-laden: they do not generally admit to a great deal of uncertainty about the future.

For our purposes, these studies are useful for initial calibration, but they are inappropriate for policy planning purposes. We required an analytic framework that arrays dissimilar industries on the same framework, permitting us to make assumptions and key parameters transparent, to examine cross-industry economic linkages, and to conduct forward-looking analyses of the important outputs of these industries.

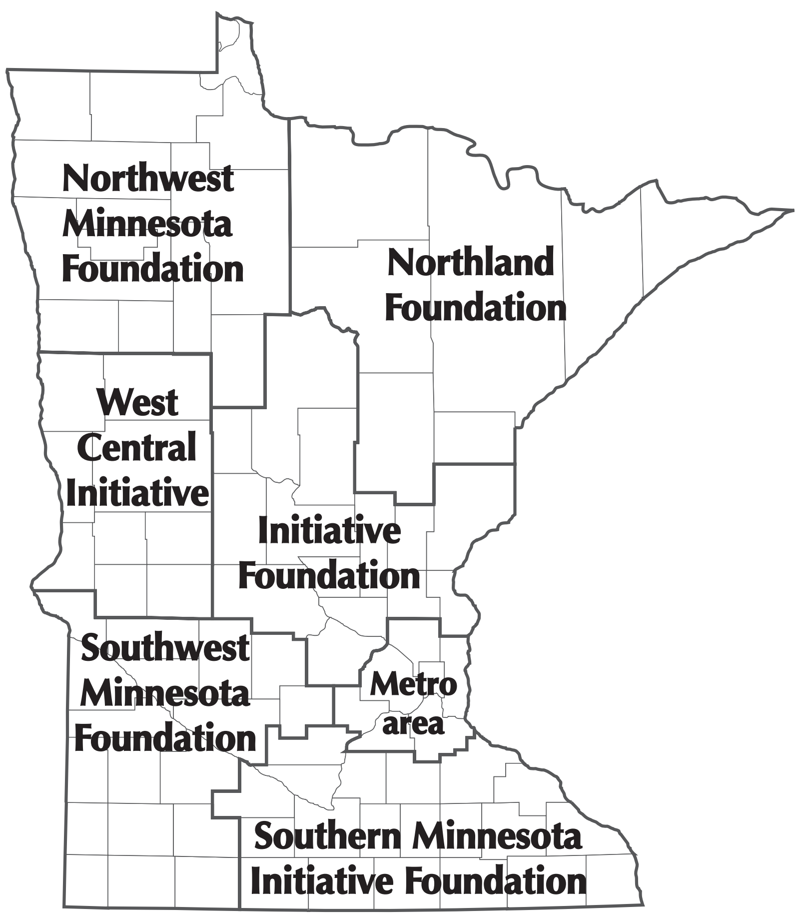
Our framework is, at its core, a set of individual facility "budgets" that track the transformation of feedstocks (corn, garbage, wind, etc.) into energy, jobs, and spending. We define each alternative energy industry as a set of "plants," each of which can be analyzed as a process that transforms resources (energy, labor, capital, physical inputs) into products (energy, co-products, waste), operating within an economic setting determined by prices in the market and policies from government. Importantly for our purposes, some of this transformation is brought about by local spending and local employment, which we use as a measure of economic development.

This budget framework allows us to estimate the region-wide and statewide implications of industry expansion or policy changes such as subsidy cuts, without having to know the details of individual plants. Where available, we used actual plant-level production and cost data. In most cases, however, this information is unavailable, so we made use of our budgets. Our assumptions are shown with each set of estimates. These (initial) assumptions are based upon our examination of the relevant literature and upon extensive discussion with state-level and national energy experts in academe, government, the industries, and non-profit organizations.

The model itself is quite flexible. We know that not all of our parameter assumptions will be agreed to. We are open to persuasion. Better assumptions, when available, will lead to better industry descriptions and predictions—and, thereby, to better policy decisions.

Where relevant, we report sub-state region totals for each energy industry, using for this purpose the boundaries of the McKnight Foundation's regional initiatives (Figure 6). (The "Metro" area is not a McKnight region; we create it for completeness.) In the production of energy, regions might vary by resource, such as wind capacity or wood supplies; by infrastructure, such as power line capacity or rail access; or by access to investment capital. Accounting for most of these geographical nuances is beyond the scope of this report. The model permits distinctions among regions, but we have not made use of this capacity to any great extent, because the appropriate data is not available. We welcome readers' insights into possible differences, and we remain open to changing model parameters to recognize regional differences if they can be supported.

Figure 6: Region boundaries in this report



Source: McKnight Foundation

Each budget includes annual capital, operating and maintenance, feedstock, local taxes, and waste disposal costs. These are balanced against revenues from energy sales, co-product sales, and subsidies (if any). All production, expenditure, and job estimates are tied to the stated production capacity of each plant.

The budgets (which we also refer to as simply "the model") are not those that would be used by any individual plant manager for investment or operating decisions. There is no public data to support such a level of analysis. We use these budgets both to estimate current production and economic impacts and to estimate future impacts should policies or industry structure change.

Many of our estimates are based on ratios that link expenditures to plant production capacity. There exists little agreement among analysts and little data among regulators about these ratios. The industries remain intensely private: little public information is available about actual employment, spending, or profitability levels.

Production estimation

Only those revenues and expenditures that are associated with energy sold into the market is calculated. This can be an important distinction for facilities, for example, that convert wood to steam for both internal use and external sales.

We assign an annual cost of capital to 100 percent of the construction cost, even though each plant will have a unique blend of debt and equity financing. We calculate the annual opportunity cost of capital to be the amortized payments at the stated contract rate and duration. This is assumed to cover both the financing costs and the depreciation of plant and equipment. All the reported estimates are based on assumed financing for 20 years at 8.0 percent interest. We estimate capital costs even for older plants that may have paid off their initial debt: the capital costs here can be interpreted as necessary replacement investments. We model both direct and indirect subsidies (producer tax credits) as if they were simple cash transfers.

The output price faced by an alternative energy production firm is independent of its actions. It is driven partly by the total actions of the industry, partly by the policies set by governments, partly by the prices charged by the rest of the energy production industry (coal, natural gas, etc.), and partly by the cost structure of the firm itself. Output prices are estimated at the plant gate. We treat all firms (producers) as price takers: they're individually so small relative to the whole market that they couldn't influence their output prices even if they tried.

Where appropriate, we net out transportation costs. Ethanol, for example, is traditionally priced at the point of delivery, not at the point of production.

Local impact estimation

The local spending category includes all direct plant expenditures except capital costs, which are assumed to be sourced largely from outside the community, and local taxes paid, which are accounted for separately in the summary tables.

Local jobs are those annually recurring maintenance, service, and administration jobs that can be directly attributed to energy production. We do not include construction jobs in this category, nor do we count jobs in the facilities that manufacture alternative energy equipment. (Besides, few of these jobs are in Minnesota, let alone in the communities that host the energy plant itself.)

Local taxes are our estimates of property taxes (and, for certain wind generation facilities, a locally paid production tax) paid on the plant and its land. We apply a fixed net effective tax rate against our estimate of the value of the plant, based upon its installed cost. This cost is charged only to privately owned systems. Cooperatives are considered to be privately owned for estimation of local tax payments.

Financial prospects

Given the technical and price assumptions noted above, we can calculate the average annual net revenues generated by energy production facilities. Of course, none of these estimates is directly applicable to any given existing facility: local conditions vary considerably. But we can (cautiously) use these estimated net revenues to examine the financial prospects (narrowly defined) of given industries under given price and policy regimes. There are myriad such regimes, of course, so we can only examine a few possibilities here.

If a plant's annual net revenue is non-zero under a set of circumstances (prices, technologies, etc.), we declare that the financial prospect for that firm is "favorable." If changing one or more of the financial or technological assumptions dramatically reverses this finding, then we consider these assumptions to be "critical." For each industry, we'll estimate both current revenue conditions and the effect of a change in one of the critical assumptions that influence net revenue. These appear in the *Prospects* section for each industry, in the form of a summary budget. Complete budget details are available from the authors.

We used these budgets to estimate the production and economic levels for each of the major alternative energy industries in the sections that follow. We summarize the core technologies used, outline the policies that influence industry behavior, and estimate the local economic impact, using the budget framework described above. We then sketch the financial prospects for industry expansion, using the budget assumptions for the construction of a hypothetical new plant of a stated size and technology.

Wood power

Production

The Minnesota wood-based energy industry consists presently only of wood and wood wastes burned in conventional systems to generate steam that runs turbines that produce electricity and heat. While gasification, pyrolysis and other more advanced conversion technologies have long been discussed, none of these are in operation in 2005.

While the wood that fuels these plants could come from traditional forest or from plantation-grown short-rotation trees such as hybrid poplar, current and expected prices are such that all of this wood will go to paper companies, not to energy plants. The paper companies are willing to pay much more for such high-quality wood than are existing and potential energy facilities. As a result, any electricity generated from wood fuels is expected to draw from waste wood, harvest residue, thinnings or paper production. (A possible exception is a proposed wood-fired plant in St. Louis County that is required to use "farm-grown" biomass as a condition for favorable price treatment under a state renewable fuels mandate. We discuss this below.)

The assumptions that support our production and impact estimates for this industry are shown in Figure 7. Even though the feedstock is "waste" wood, it has a real cost, if only in the value it has if it were to be used elsewhere.

Figure 7: Wood power budget assumptions

capacity factor	0.80
installed cost ($/MW capacity)	2,000,000
wood cost ($/ton)	10
O&M cost ($/kWh produced)	0.02
local jobs (per MW capacity)	0.25
local tax (% installed cost)	2.0
fuel conversion (kWh/ton)	1,875
electricity price ($/kWh)	0.03
energy conversion (Btu/kWh)	3,413
waste generation (lb/ton fuel)	500
waste disposal cost ($/T fuel)	25

Policies

New commercial biomass-sourced power is eligible for the federal renewable tax credit of \$0.009/kWh for all output for the first five years of operation. It is not known which plants in Minnesota are receiving this credit, although our estimates are based on the assumption that only the relatively new St. Paul waste wood plant is eligible. Because the subsidy is available only for the first five years, we model it by reducing it to one-fourth of the base level: five years divided by our assumed 20-year plant life.

Minnesota exempts certain specific biomass power plants from paying property tax on machinery and equipment for the first five years of operation. The exemption also applies to any waste wood facility and to any locally endorsed facility. We do not include these short-term subsidies in the wood power budgets.

As a condition for the state extending the license for Xcel Energy to store spent nuclear materials at its Prairie Island nuclear generating facility in Dakota County, Xcel is required to purchase a certain level of renewable energy each year. Most of the energy so purchased has been generated by wind power, but District Energy, a waste wood facility in St. Paul, did contract on extremely favorable terms under the biomass mandate. In addition, a contract for the output of a 50 MW plant was initially extended to a plant to be built in St. Peter and fueled by plantation-grown hybrid poplars. That facility was never built, but the contract (now reduced to 35 MW) was transferred to a group in Waseca that proposed a similar facility, also to be fueled by hybrid poplars. That plant, too, was never built. The Xcel contract was transferred a third time to a consortium of utilities on the Iron Range, in St. Louis County. At the time of this writing (December 2005), only a few hundred acres of land have been planted to poplars, and the plant is not yet producing electricity under a biomass mandate contract.

Local impact

Only a handful of wood-burning facilities in Minnesota both generate energy *and* sell it to the grid. All but one are in the northern part of the state, usually linked (if only by contract) to a nearby paper mill. Sales to the grid are often only a small portion of their total energy production. District Energy in St. Paul generates both electricity for sale to the grid and heating and cooling power for local businesses and residences. Here, too, the power sold to the grid, which is the only type of generation we're interested in here, is only a portion of the plant's total energy production.

Figure 8 summarizes our estimates of the sales, expenditures, and associated jobs for each of the wood power facilities. These estimates hinge critically on our assumptions about the proportion of installed capacity allocated to external power sales.

Figure 8: Estimated Minnesota wood power production and local impacts, 2005

County	Plant	Power sold to market (MWh)	Local jobs related to power production	Local spending on power production	Local taxes paid on power production
Itasca	Rapids Energy Center	176,602	15.8	4,709,261	1,260,000
Koochiching	Boise Cascade	121,200	8.6	3,231,921	691,781
Carlton	Sappi Paper	303,200	21.6	8,085,136	1,730,594
St. Louis	Hibbard Energy Center	392,448	35.0	10,465,025	2,800,000
Ramsey	District Energy	140,160	12.5	3,737,509	1,000,000
	State	**1,133,610**	**93.5**	**30,228,851**	**7,482,374**

Prospects

Given our assumptions about the key financial parameters for wood power production, it would be unlikely for new dedicated power facilities to flourish unless they could gain access to cheaper wood or sell electricity at above-market rates. Only waste wood from paper or particle board production, urban waste wood, slash and trimmings from forest harvest, or dead wood from blow-downs is likely to be used in energy production in the near future — barring technical breakthroughs that might reduce energy production costs sufficiently to warrant higher prices for plantation-grown wood or a dramatic change in fossil energy prices.

What we could see is more use of wood for in-plant energy needs (especially heat). Few cities generate sufficient waste wood for a district heating/cooling system such as that in St. Paul and that planned by the Green Institute in Minneapolis, but there may be situations in which existing wood-fired plants can profitably sell such services to businesses in the vicinity. A variant on this theme is a proposed modification to an existing ethanol plant in Little Falls that will use wood to generate much of the power required in ethanol production.

Figure 9 shows the influence of operating costs on the revenue estimate for a new privately owned 20 MW wood power plant. Our budgets suggest that the new plant would generate negative annual net returns under initial assumptions. (Current facilities can remain in operation, even though we estimate their net revenues to be negative, because they are willing to operate at a loss on paper because the power unit saves them money overall by reducing waste disposal costs or by replacing power purchases. We do not model whole-plant finances in this report.) If operating costs were 25 percent lower, the new plant would still show a negative estimated net revenue.

Figure 9: Estimated annual effects of reduction in wood power O&M cost

	New 20MW privately owned wood power plant	Same plant if O&M costs reduced by 25%
Debt service	4,074,088	4,074,088
O&M	2,242,560	1,681,920
Feedstocks	597,958	597,958
Local taxes	800,000	800,000
Other costs	149,489	149,489
TOTAL cost	7,864,095	7,303,455
Energy sales	3,363,840	3,363,840
Other revenue		
Subsidy	252,288	252,288
TOTAL revenue	3,616,128	3,616,128
NET revenue	(4,247,967)	(3,687,327)

Landfill gas power

Production

As municipal solid waste decomposes in the anaerobic confines of a sealed landfill, it generates a substantial amount of methane gas. At one time, this gas was permitted to escape into the atmosphere, but this practice has fallen into disfavor, especially with the pinpointing of methane as a contributor to global warming. This attention has led in the past few decades to the requirement that all closed landfills (and completed portions of working landfills) be fitted with methane capture systems.

In a few of these facilities, the gas is prevented from escaping by a system of non-permeable covers and collection piping, and the methane is cleaned and then routed to a turbine to generate electricity. (Similar technologies have long been used in wastewater treatment facilities, where methane is also generated. There, traditionally, the gas is burned for heat that is then used in the treatment process. We are aware of no wastewater treatment plants in Minnesota that generate power and sell it into the grid.)

Our budget assumes that the cost of the gas collection system is necessary whether or not electricity is generated. Consequently, this cost is not included in our installed cost estimate.

Figure 10: Landfill gas power budget assumptions

capacity factor	0.90
installed cost ($/MW)	1,300,000
total cost ($/kWh)	0.018
electricity price ($/kWh)	0.03
waste generated (lbs.)	0
Energy conversion (Btu/kWh)	3,413
local tax (% installed cost)	2.0
local jobs per MW installed	0.25

Policies

New (since 2004) commercial landfill gas facilities may be eligible for a $0.009/kWh federal tax credit for the first five years of operation. Because the subsidy is available only for the first five years, we model it by reducing it to one-fourth of the base level: five years divided by our assumed 20-year plant life. Public facilities are eligible for the same payment in cash, subject to available federal funding. In our estimates, we assume that the available funding for public facilities is zero.

Local impact

There are four landfill gas/electricity production facilities operating in Minnesota in 2005, all in the metropolitan area. These jointly produce over 169,000 MWh each year, creating five jobs in total.

Figure 11: Estimated Minnesota landfill gas power production and local impacts, 2005

County	Landfill name	Power sold to market (MWh)	Local jobs related to power production	Local spending on power production	Local taxes paid on power production
Hennepin	Flying Cloud	37,843	1.2	681,178	124,800
Hennepin	Burnsville	32,324	1.0	581,839	106,600
Dakota	Pine Bend	78,840	2.5	1,419,120	260,000
Sherburne	Elk River	19,710	0.6	354,780	65,000
	State	**168,718**	**5.4**	**3,036,917**	**556,400**

Prospects

The Minnesota Pollution Control Agency, which has jurisdiction over (and, in many instances, ownership of) closed landfills, is presently asking firms for bids to access the methane (over which the state has asserted ownership rights) from several landfills, in the hope of increasing energy production from these sites.

Our budgets estimate that the annual net revenues for a landfill gas facility are negative, principally because of the high initial cost for the generating equipment. If this cost could somehow be reduced by 30 percent — through favorable financing terms or new technologies, for example — this deficit would almost be erased.

Figure 12: Estimated annual effects of reduction in landfill gas power capital costs

	New 20MW publicly owned landfill gas plant	Same plant if capital cost reduced 30%
Debt service	2,648,157	1,774,265
O&M	2,838,240	2,838,240
Feedstocks		
Local taxes	—	—
Other costs		
TOTAL cost	5,486,397	4,612,505
Energy sales	4,730,400	4,730,400
Other revenue		
Subsidy	—	—
TOTAL revenue	4,730,400	4,730,400
NET revenue	(755,997)	117,895

Garbage power

Production

Garbage has been burned for energy for decades in Minnesota, with mixed success financially and environmentally. The usual process is to screen the arriving refuse for metals and glass and other recyclables, then shred the remaining material, letting the moisture content become more uniform, then burn it either alone or mixed with coal. The process removes much of the embedded energy, but still results in a substantial amount of relatively inert ash and clinkers that must be eventually sent to a landfill (although there have been frequent attempts to use some of the ash in construction or roadway materials).

Figure 13: Garbage power budget assumptions

capacity factor	0.90
installed costs ($/MW)	1,200,000
O&M costs ($/kWh)	0.05
tipping fee ($/ton MSW)	25
waste generation (lb/ton MSW)	500
waste disposal cost ($/ton waste)	25
local jobs per MW capacity	0.5
electricity price ($/kWh)	0.03
energy conversion (Btu/kWh)	3,413
local tax (% installed cost)	2.0
fuel conversion (ton/MWh)	1.3

Policies

New privately owned garbage power generation facilities may be eligible for a $0.009/kWh federal tax credit for their first five years of operation. This is useful only for investors who have passive income against which to apply the credit. Because the subsidy is available only for the first five years, we model it by reducing it to one-fourth of the base level: five years divided by our assumed 20-year plant life. Publicly owned facilities do not receive a federal or state subsidy.

Local effects

There are only four plants that regularly generate electricity for sale from municipal solid waste. Figure 14 summarizes estimated production from these facilities. One of the important revenues for a garbage power plant is the “tipping fee” it charges for disposing of garbage through the plant rather than at the presumably more expensive (or now prohibited) landfill. These tipping fees are essentially a negative “cost” for energy feedstocks. The more efficiently a system converts garbage into power, the less garbage it needs. This results in less waste to dispose of, but it also results in a lower demand for garbage in the first place (for a given plant output capacity), with its associated lower revenue from tipping fees.

The power output shown in the summary charts is that actually sold to energy markets, net of any production that goes to in-plant uses.

Figure 14: Estimated Minnesota garbage power production and local impacts, 2005

County	Plant name	Power sold to market (MWh)	Local jobs related to power production	Local spending on power production	Local taxes paid on power production
Goodhue	Red Wing	181,332	11.5	10,539,923	322,000
Blue Earth	Wilmarth	197,100	12.5	11,456,438	350,000
Sherburne	Elk River	305,899	19.4	17,780,391	543,200
Hennepin	Covanta	311,418	19.8	18,101,171	—
Olmsted	Olmsted Energy	197,100	12.5	11,456,438	—
STATE		1,192,849	75.7	69,334,360	1,215,200

Prospects

Garbage power is unpopular in energy circles at present, due in part to the difficulties existing facilities have had in materials handling and plant maintenance. Newer gasification technologies have been suggested, but none are being seriously considered in Minnesota. We estimate net revenues for new garbage power plants to be negative. If tipping fees were to be increased by 20 percent (to $30/ton MSW), however, the hypothetical plant would show positive annual net returns.

Figure 15: Estimated annual effects of increase in garbage power tipping fees

	New 20MW publicly owned garbage power plant	Same plant if tipping fee increased 20%
Debt service	2,444,453	2,444,453
O&M	7,884,000	7,884,000
Feedstocks		
Local taxes	—	—
Other costs	1,281,150	1,281,150
TOTAL cost	11,609,603	11,609,603
Energy sales	4,730,400	4,730,400
Other revenue	5,124,600	6,149,520
Subsidy	—	—
TOTAL revenue	9,855,000	10,879,920
NET revenue	(1,754,603)	(729,683)

Wind power

Production

The only thing new about wind power production is its scale: we've seen small windmills on the rural (and occasionally urban) horizon for generations. Recent advances in generating equipment, coupled with generous state and federal subsidies, have made it possible to greatly expand the commercial side of this business in Minnesota. The newer (since 2002 or so) wind towers are over 250 feet tall, with blades that span 200 feet or more, and are rated at 1.5 - 2.5 MW. While any given tower may not be producing at a given moment because the wind is blowing too slow or too fast, a set of hundreds of such towers can provide a reasonable level of consistent power for the utility that buys and then distributes that power.

Wind turbines are also rated by their capacity factor, a combination of how fast and how often the wind is blowing and how efficiently the turbine translates that wind energy into electricity. Factors in Minnesota range from 0.2 in the less desirable areas to 0.4 in some southwestern areas. In our estimates, we used a factor of 0.3 for all regions.

Figure 16: Wind power budget assumptions

installed costs ($/MW)	1,000,000
maintenance ($/kW capacity)	17.50
insurance ($/kW capacity)	10.30
land lease ($/turbine)	4,000
local tax ($/kWh))	0.00012-.0012
energy conversion (Btu/kWh)	3,413
capacity factor	0.3
local jobs per MW capacity	0.1

Policies

Wind power is eligible for the federal renewable tax credit of $0.018/kWh ($.015 for plants built prior to 2004) for the output of all wind generation facilities for the first ten years of operation. Because the subsidy is available only for the first ten years, we model it by reducing it to one-half of the base level: 10 years divided by our assumed 20-year plant life. The state pays $0.015/kWh to production from small projects, defined as under 2 MW in total size, for the first ten years. We model current payments at the same 50 percent level as for the federal credits. This applies only to eligible wind farms constructed prior to 2005; the program is no longer in place.

Wind power facilities are largely exempt from local property taxes and state sales taxes. (The land on which the tower sits is, however, subject to property tax.) After local governments complained that they were unable to gain revenues from wind facilities, the state imposed a production tax on wind power, ranging from $.00012 per kWh for smaller plants to $.0012 for larger plants. This tax is administered by local authorities, and its proceeds are distributed to local taxing jurisdictions, just as the property tax is. In our estimates, the production tax is reported as a local tax.

Finally, Xcel Energy is required, as discussed above, to purchase a certain amount of power each year from renewable sources. Most of the company's renewable portfolio has turned out to be in wind power. In order to secure that power, the company has entered into long-run supply contracts with wind energy producers, presumably at favorable terms to the producers. Xcel Energy is also required to pay $0.033/kWh for the output of any wind "project," as defined above, whether or not under the mandated contracts.

Local impact

There are hundreds of windmills in Minnesota regularly producing electricity for sale through the grid. Most are presently in the southwestern part of the state. The ownership structure varies greatly. Many producers operate only a few windmills — there are some policy incentives to be considered "small" — while a few wind farms control the output of several score turbines.

In Figure 17, we show only those "wind farms" that total more than 10 MW in combined capacity. We then aggregate all the known wind power facilities to the regional level, using the boundaries discussed above (Figure 18).

Figure 17: Larger Minnesota wind energy facilities, 2005

County	Wind farm	Year built	Capacity
Lincoln	Lake Benton I	1998	107.2
Lincoln	Lake Benton II	1999	103.5
Murray	Chanarambie Power Partners, LLC	2003	85.5
Pipestone	Moraine Wind LLC	2004	51.0
Murray	N/A.	2004	36.0
Dodge	Dodge Center	2002	34.0
Lincoln	Buffalo Ridge Windplant WPP 1993	1994	25.0
Mower	McNeilus	2004	22.8
Mower	N/A.	2004	19.5
Lincoln	Ruthton	2004	15.8
Murray	Viking Wind Partners	2003	12.0
Lincoln	Shaokatan Hills LLC	1999	11.9
Lincoln	North Shaokatan	2004	11.9
Rock	Minwind 3-9	2004	11.5
Lincoln	Lakota Ridge LLC	1999	11.2
Pipestone	Woodstock Windfarm	1999	10.2

By the end of 2005, Minnesota's wind energy industry will generate nearly 1.7 GWh of electricity. This will still be only a small proportion of the state's electricity demand (we estimate this to be 68 GWh in 2005, based upon a 3-percent growth rate from the reported 2001 level), but wind power production in the southwest region will amount to about three-quarters of local demand.

Figure 18: Estimated Minnesota wind power production and local impacts, by region, 2005

	Rated capacity (MW)	Power sold to market (MWh)	Electricity demand (MWh)	Local jobs	Local spending (million)	Local taxes (million)
Initiative	—	—	7,799,392	—	—	—
Metro	5.2	13,666	31,909,793	0.5	0.2	0.0
Northland	—	—	9,679,583	—	—	—
Northwest	—	—	2,836,490	—	—	—
Southern	80.0	210,109	8,610,692	8.0	2.4	0.2
Southwest	554.1	1,456,175	4,396,922	55.4	16.9	1.4
West Central	3.3	8,672	2,659,483	0.3	0.1	0.0
STATE	**642.6**	**1,688,621**	**67,892,355**	**64.3**	**19.6**	**1.7**

Prospects

The wind power industry is thought by some to be close to being self-sustaining, in the sense that it can make money without a subsidy, but our estimates do not support this contention. Under our assumptions, annual net revenues for a new 20 MW wind farm are below zero to begin with: they improve to (roughly) zero if the state subsidy is renewed.

Figure 19: Estimated annual effects of renewal of state wind power subsidy

	New 20MW privately owned wind farm	Same facility if state subsidy renewed
Debt service	2,322,230	2,322,230
O&M	609,333	609,333
Feedstocks		
Local taxes	84,096	84,096
Other costs		
TOTAL cost	3,015,660	3,015,660
Energy sales	2,102,400	2,312,640
Other revenue		
Subsidy	665,760	665,760
TOTAL revenue	2,768,160	2,978,400
NET revenue	(247,500)	(37,260)

Ethanol fuel

Production

There are two principal ethanol production technologies: wet milling, of which there is only one in Minnesota, and dry milling, which accounts for all of the other plants in the state. While other feedstocks are technically feasible (and may prove financially desirable in the future), only corn is used in the existing plants. The only part of the corn plant that is used is the kernel, which is ground, then subjected to various chemical processes. Dry mills produce as a co-product distiller dried grains, which are sold as a high-quality animal feed, and in some plants CO2, which is sold into the commercial market. Wet mills also produce in varying quantities starch, high fructose corn syrup, and assorted "mill products." Almost all of the ethanol produced in Minnesota goes into motor fuels, blended in a 10-percent mixture with gasoline.

Figure 20 shows our initial budget assumptions. We use a single corn price for the entire state. Even a sizeable ethanol plant has little effect on local corn prices, because the state's corn production is so large, and the effective market is so expansive. This is not to say that an ethanol plant might not have some effect in a limited range around the plant. Because corn prices are lower the farther the production is from the major marketing points, an ethanol plant can secure sufficient corn by offering a price slightly higher than that offered through conventional markets to producers "upstream" from the plant. But this is not expected to be a very large price increment, certainly well within the price swings that corn growers experience during the course of the marketing year. In our estimates of feedstock acquisition cost, we do not account for a local price premium, if any.

Figure 20: Ethanol budget assumptions

	Dry mill	Wet mill
capacity factor	1.10	1.10
corn cost ($/bu used)	2.20	2.20
energy cost ($/gal produced)	0.17	0.15
chemical cost ($/gal produced)	0.11	0.14
other cost ($/gal capacity)	0.13	0.20
ethanol conversion (gal/bu)	2.89	2.50
DDG conversion (lb/bu)	18.00	N/A
CO2 conversion (if used) (lb/bu)	18.00	16.00
corn oil conversion (lb/bu)	N/A	1.60
21% gluten feed conversion (lb/bu)	N/A	10.00
60% gluten feed conversion (lb/bu)	N/A	2.00
ethanol price ($/gal)	1.150	1.150
DDG price ($/lb)	0.040	N/A
CO2 price ($/lb)	0.003	N/A
corn oil price ($/lb)	N/A	0.250
21% gluten feed price ($/lb)	N/A	0.050
60% gluten feed price ($/lb)	N/A	0.100
local tax (% installed cost)	0.02	2.0
waste generation (lb/gal produced)	0	0
energy conversion ((Btu/gal)	75,700	75,700
Capacity (million gal.)	**Local jobs per million gal capacity**	**Installed cost ($/gal Capacity)**
Under 10	1.00	1.70
10-20	0.95	1.65
20-30	0.90	1.60
30-40	0.85	1.55
Over 40	0.80	1.50

Policies

The state of Minnesota pays $0.13/gallon for the first 15 million gallons of production in each of the first ten years of a plant's operation. (The Marshall, Morris, Winnebago, and Winthrop plants are old enough to be no longer eligible for the subsidy. The Atwater, Granite Falls, and Lake Crystal plants will open after the state subsidy coffers are empty.) Because the subsidy is available only for the first ten years, we model it by reducing it to one-half of the base level: 10 years divided by our assumed 20-year plant life.

In addition, the federal government offers a federal fuel tax exemption at a rate equivalent to $0.52 to the seller of the resulting blended gasoline product. In our estimates of revenues, we assume that all of this subsidy is passed through to the ethanol producer. Thus, our estimated ethanol price implicitly includes this blender subsidy.

The state of Minnesota mandates that almost all gasoline sold in the state be a 10-percent ethanol blend. This policy is not directly modeled here: it has the effect of ensuring that a sizeable proportion of current production is sold within the state.

Finally, any expanded (or new) ethanol facility receives a one-year federal cash payment equivalent to their increased cost of U.S.-grown corn. We do not model this one-time subsidy in our estimates of plant revenues.

Local impacts

By the end of 2005, fifteen Minnesota facilities will be producing nearly 600 million gallons of ethanol, resulting in 450 local jobs. Figure 21 shows the plants and where they're located, and Figure 22 aggregates production and impact estimates by sub-state regions. Our local job estimate is considerably lower than the number often cited by ethanol industry proponents, in part because those other estimates also include indirect job creation such as truckers hauling corn and refinery workers blending the final fuels, whereas we're interested only in local direct job creation.

Figure 21: Estimated Minnesota ethanol production, 2005

County	City	Year constructed	Ethanol production (million gallons)
Blue Earth	Lake Crystal	2005	52.8
Dodge	Claremont	1996	37.4
Faribault	Winnebago	1994	49.5
Fillmore	Preston	1998	44.0
Freeborn	Albert Lea	1999	44.0
Kandiyohi	Atwater	2005	44.0
Lyon	Marshall	1988	40.0
Morrison	Little Falls	1999	24.2
Renville	Buffalo Lake	1997	19.8
Rock	Luverne	1998	23.1
Sibley	Winthrop	1995	40.7
Stevens	Morris	1991	26.4
Swift	Benson	1996	48.4
Watonwan	Bingham Lake	1997	33.0
Yellow Medicine	Granite Falls	2005	52.8

Figure 22: Estimated Minnesota ethanol production and local impacts, by region, 2005

	Number of plants	Ethanol sales (million gallons)	Local jobs	Local spending (million dollars)	Local taxes paid (million dollars)
Initiative	1	24.2	19.8	28.1	0.7
Metro	—	—	—	—	—
Northland	—	—	—	—	—
Northwest	—	—	—	—	—
Southern	7	301.4	229.8	349.5	8.4
Southwest	6	228.1	177.6	268.1	6.5
West Central	1	26.4	21.6	30.6	0.8
STATE	**15**	**580.1**	**448.8**	**676.3**	**16.4**

Prospects

In May 2005, the Minnesota Legislature increased the mandated blend of ethanol in motor fuels from 10 percent to 20 percent by 2013, conditional upon certain changes in federal policy. The Minnesota Department of Agriculture estimates that this increase would result in an in-state ethanol demand of 574 million gallons annually. Our estimates in Figure 23 show that the state's existing facilities (including planned 2005 additions) would be able to meet this demand—at the expense of current exports from the state. So the short-run local impacts of the increase to a 20-percent blend are zero. In the longer run, however, if Minnesota producers remain competitive in export markets (markets outside of Minnesota) — and the current scale of the state's ethanol exports suggests that they are — then the new state mandate will have the effect of increasing the total potential market for Minnesota ethanol. This potential would require expanded or new production facilities, with their associated local job and spending gains.

Also in the longer run, as in-state motor fuel demand increases with economic growth (assuming current demand factors remain the same) and if a few older plants go out of production, the new demand may require either expansion of ethanol production in Minnesota or imports from other states.

What if the federal government were to reduce the blender tax credit by, say, 50 percent? If the credit is currently fully passed through to ethanol producers, as we assume it is here, this would show up in our budget as a decrease in the plant-gate price of ethanol by $0.26/gallon. The second column in Figure 23 shows how anticipated net revenues for a new 40-million gallon plant would be affected. This plant would not generate positive net revenues if the tax credit were reduced by this amount.

However, as gasoline prices rise in comparison to ethanol, our assumption of full pass-through becomes less tenable. Indeed, McCullough and Etra (2005) argue that when the crude oil price rises above $45/barrel, ethanol market prices are not affected at all by the federal blender credit: all the subsidy is effectively retained by the blender, not passed on to the ethanol producer. If this is true, even abolishing the federal credit would have no impact on ethanol plant productivity — as long as oil prices remained high.

Figure 23: Estimated annual effects of reduction in federal ethanol tax credit

	New 40 MG privately owned ethanol dry mill	Same facility if federal blender credit cut by 50%
Debt service	6,314,837	6,314,837
O&M	12,320,000	12,320,000
Feedstocks	33,494,810	33,494,810
Local taxes	1,240,000	1,240,000
Other costs	5,200,000	5,200,000
TOTAL cost	58,569,647	58,569,647
Energy sales	50,600,000	39,160,000
Other revenue	10,961,938	10,961,938
Subsidy	—	—
TOTAL revenue	61,561,938	50,121,938
NET revenue	2,992,291	(8,447,709)

Biodiesel fuel

Production

Biodiesel facilities convert some of the energy stored in plant oils or animal fats into fuel and glycerine "bottoms." Several new technologies promise other co-products from biodiesel, but none of these are in commercial use at this time. The feedstock can be animal fats ("yellow grease," in the trade) or soybean oil. In our estimates, we model the technology as one of conversion of oils into fuel. We consider the soybean crush, the process by which oils are extracted from the beans to be a separate process, not under the accounting oversight of our models.

Figure 24: Biodiesel budget assumptions

	Soybean oil	**Yellow grease**
capacity factor	1.10	1.10
soy oil cost ($/lb used)	0.22	
labor cost ($/gal capacity)	0.04	0.04
maintenance (% installed cost)	0.04	0.04
overhead ($/gal capacity)	0.02	0.02
energy cost ($/gal capacity)	0.02	0.04
chemical cost ($/gal capacity)	0.18	0.18
property tax rate (% installed cost)	0.02	0.02
jobs per million gallons capacity	0.25	0.25
soy oil conversion (gal/lb)	0.14	
yellow grease conversion (gal/lb)		0.14
yellow grease cost ($/lb)		0.14
glycerine conversion ($/gal output)	0.20	0.20
biodiesel price ($/gal)	1.30	
blender credit pass-through ($/gal)	1.00	
glycerine price ($/lb)	0.95	
energy conversion (Btu/gal)	125,000	125,000
local tax (% installed cost)	0.02	2.0
waste generation (lb/gal produced)	0	0
waste disposal cost ($/ton)	25.00	25.00

Policies

Biodiesel blenders receive a $1.00 federal tax credit for each gallon of biodiesel used instead of conventional diesel. (The credit is $0.50 per gallon for biodiesel made from recycled oils such as yellow grease.) In our budgets, we assume this credit is passed through (at least in part) to the biodiesel producer, and so it is embedded in the price the producer receives.

Any expanded (or new) soybean oil biodiesel facility receives a one-year federal cash payment equivalent to their increased cost of U.S.-grown beans. We do not model this one-time subsidy in our estimates of plant revenues.

As of mid 2005, Minnesota will require that all diesel fuel sold in the state be at least 2 percent biodiesel. Ye (2004) estimates that this would require 122 million to 306 million pounds of soybean oil, roughly half the input for one of the plants that are to come on line in 2005. We model this purchase mandate (and that for ethanol) indirectly as a guaranteed market for Minnesota-produced biodiesel.

Local impacts

Three biodiesel plants are due to open in 2005 in Minnesota. The Redwood Falls plant will convert yellow grease, while the other two are soybean oil plants. As is the case with ethanol, biodiesel production, once on line, will clearly lead to local economic gains in expenditures and jobs, as shown in Figure 25.

Figure 25: Estimated annual Minnesota biodiesel production and local impacts, 2005

County	City	Biodiesel sales (million gallons)	Local jobs	Local spending	Local taxes paid
Nobles	Brewster	33.0	8.3	61,157,000	750,000
Freeborn	Albert Lea	33.0	8.3	61,157,000	750,000
Redwood	Redwood Falls	3.5	0.9	4,870,000	115,000
	State	**69.5**	**17.4**	**127,185,000**	**1,615,000**

Prospects

This is the newest of Minnesota's alternative energy production technologies, so several of our assumptions are untested in practice. We don't know for sure even that the plants coming on line in 2005 will be profitable, although Figure 26 suggests that, given the assumptions that underlie our budgets, they would be. The figure shows our estimate of the net revenue from a new 40 MG plant using soybean oil for its feedstock. With current subsidies in place (and holding all other price and production parameters constant), we estimate that the plant would have positive net revenues in a typical year. But the subsidy—and the pass-through assumption—is critical here, as it was with ethanol profitability. If the federal blender tax credit were to be cut by $.25, for example, the assumed plant gate price for biodiesel would drop to $1.75/gallon—wiping out the estimated current profit. As with ethanol, our estimated impact of federal subsidy cuts depends critically on whether or not our assumption of full credit pass-through is correct. If conventional diesel prices continue to increase, however, the assumption is called into question, because blenders will be better able to retain some or all of the credit and still meet the purchase price of biodiesel producers.

Figure 26: Estimated annual effects of reduction in federal blender credit

	New 40 MG privately owned biodiesel plant	Same facility if federal blender credit cut by $0.25
Debt service	4,685,202	4,685,202
O&M	12,240,000	12,240,000
Feedstocks	69,142,857	69,142,857
Local taxes	920,000	920,000
Other costs		
TOTAL cost	86,988,059	86,988,059
Energy sales	88,000,000	77,000,000
Other revenue	8,360,000	8,360,000
Subsidy	—	—
TOTAL revenue	96,360,000	85,360,000
NET revenue	9,371,941	(1,628,059)

Industry production and impact summary

Figures 27 and 28 summarize our production and local economic impact estimates for all six alternative energy industries. The 2005 estimates in Figure 27 will not be directly comparable to EIA data for the same year — once these eventually appear — because the EIA creates a “residual” category to account for production that the EIA thinks is occurring but doesn’t have any specific plant-level data to prove it. Our estimates are based solely upon plants and plant characteristics that we can explicitly account for. The difference between the two data sources is especially evident for wood power plants: several facilities have been added to the list since the EIA estimates were published.

Figure 27: Estimated Minnesota alternative energy production and local impacts, by industry, 2005

FUELS	Production (million gallons)	Local jobs	Local spending (million dollars)	Local taxes paid (million dollars)
ethanol	580.1	448.8	676.3	16.4
biodiesel	69.5	17.4	127.2	1.6
STATE	**649.6**	**466.1**	**803.4**	**18.0**

ELECTRICITY	Production (MWh)	Local jobs	Local spending (million dollars)	Local taxes paid (million dollars)
wind power	1,688,621	64.3	19.6	1.7
garbage power	1,192,849	75.7	69.3	1.2
wood power	1,133,610	93.5	30.2	1.3
landfill gas power	168,718	5.4	3.0	0.6
State	**4,183,798**	**238.8**	**122.2**	**4.7**

Figure 28: Estimated Minnesota alternative energy production and local impacts, by region, 2005

	Fuels (million gallons)	Electricity (MWh)	Local jobs	Local spending (million dollars)	Local taxes (million dollars)
Initiative	24.2	325,609	39.8	46.2	1.7
Metro	—	614,251	37.5	24.7	1.5
Northland	—	993,450	81.0	26.5	6.5
Northwest	—	—	—	—	—
Southern	334.4	785,641	282.5	446.5	10.6
Southwest	264.6	1,456,175	242.1	351.0	8.8
West Central	26.4	8,672	21.9	30.7	0.8
State	**649.6**	**4,183,797.8**	**704.9**	**925.6**	**29.8**

Industry expenditure and revenue summary

Using the estimated revenues from the prospects sections of each of the alternative energy industries analyzed in the previous sections, we can compare prospects across all industries, as in Figure 29. Ethanol and biodiesel facilities are estimated to have positive net revenues, while the other four industries have negative profits, given our initial assumptions.

Figure 29: Estimated annual costs and returns for hypothetical alternative energy facilities

	Ethanol	Biodiesel	Wind	Garbage	Wood	Landfill Gas
Facility size	40 MG	40 MG	20 MW	20 MW	20 MW	20 MW
Debt service	6,314,837	4,685,202	2,322,230	2,444,453	4,074,088	2,648,157
O&M	12,320,000	12,240,000	609,333	7,884,000	2,242,560	2,838,240
Feedstocks	33,494,810	69,142,857		—	597,958	
Local taxes	1,240,000	920,000	84,096	—	800,000	—
Other costs	5,200,000	—		1,281,150	149,489	
	58,569,647	86,988,059	3,015,660	11,609,603	7,864,095	5,486,397
Energy sales	50,600,000	88,000,000	2,102,400	4,730,400	3,363,840	4,730,400
Other revenue	10,961,938	8,360,000		5,124,600		
Subsidy	—	—	665,760	—	252,288	—
	61,561,938	96,360,000	2,768,160	9,855,000	3,616,128	4,730,400
NET REVENUE	**2,992,291**	**9,371,941**	**(247,500)**	**(1,754,603)**	**(4,247,967)**	**(755,997)**

Figures 30 and 31 show the estimated costs and returns converted to a per-bBtu (billion British thermal unit) basis, using the conversion ratios listed in each industry's budget assumptions table. The charts clearly demonstrate the relatively low local spending impact of wind power, for example, or the large reliance by garbage power facilities on "other" revenue, in this case the imposition of tipping fees.

Figure 30: Estimated costs per billion Btu output

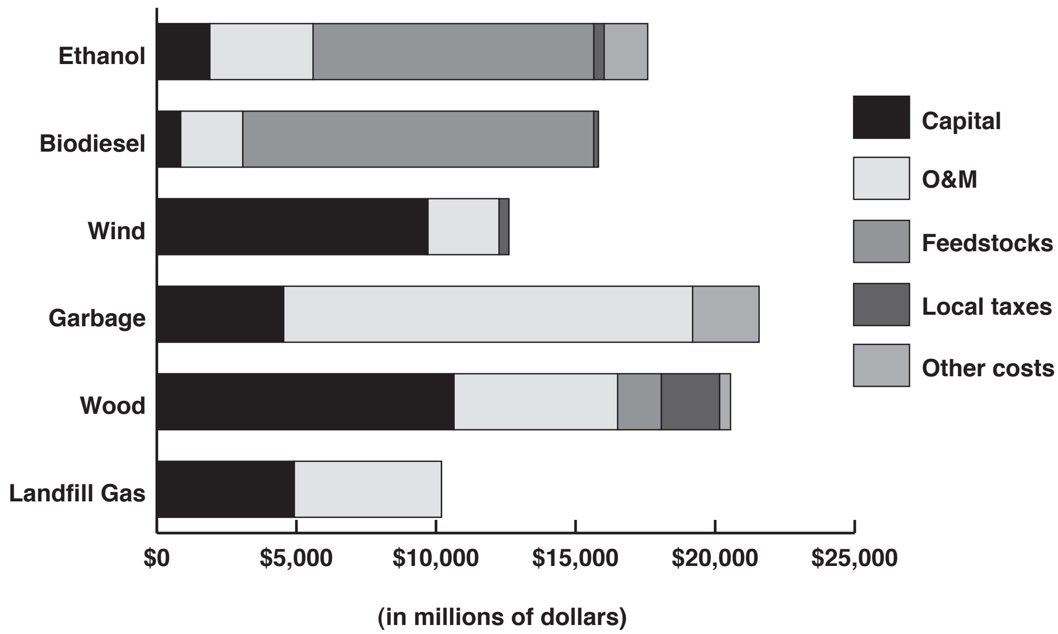


Figure 31: Estimated revenues per billion Btu output

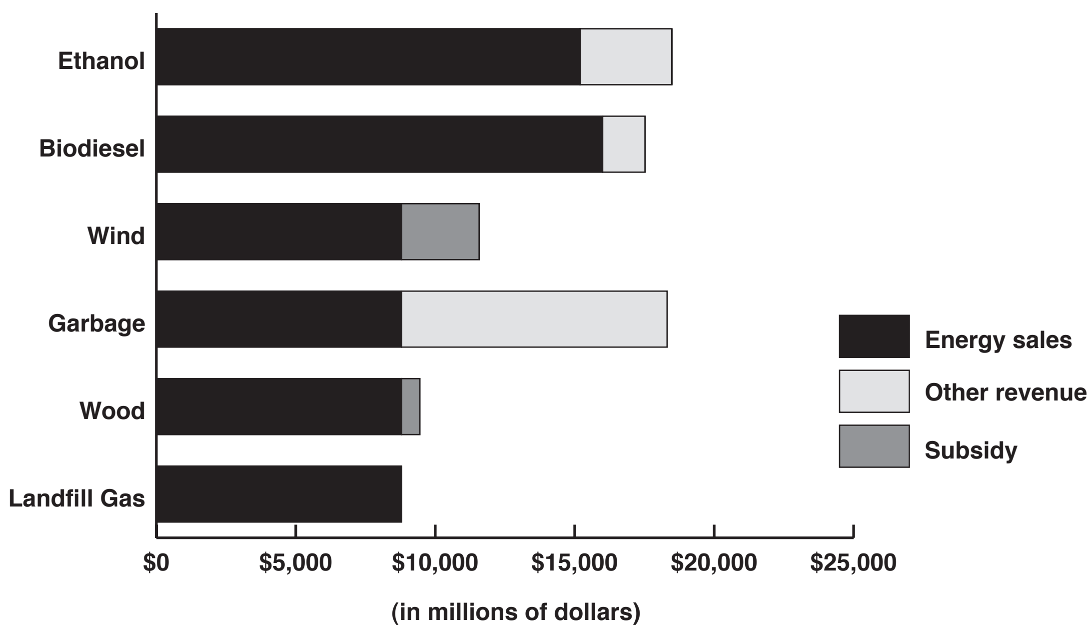


Figure 32 makes use of our estimates to ask a possible policy question: If the state had, say, a million dollars to invest in one and only one alternative energy industry, where should that investment go? Ethanol and biodiesel plants already have estimated positive net revenues, so the state need not invest further in these technologies. But the other four technologies, with estimated negative revenues, would require additional subsidy to trigger their development. Figure 32 shows the number of new jobs that would result for each million dollars spent annually to raise the net revenues for each typical plant to zero. Our estimates suggest, surprisingly to us, that garbage power plants generate more local jobs per dollar invested than any of the other alternative energy industries. This finding, like any other drawn from our analysis, depends critically upon the budget and technology assumptions detailed in each industry section.

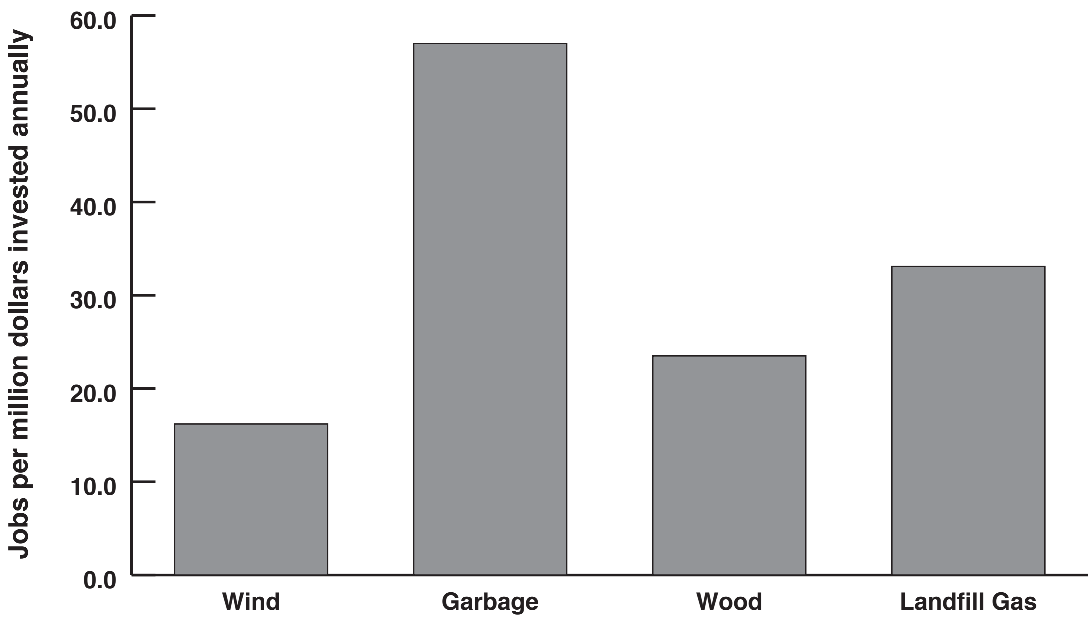


Figure 32: Estimated number of local jobs created by alternative energy investment

Alternative energy industry opportunities

We've shown that Minnesota's alternative energy industries supply only a very small portion of current state demand for electricity and motor fuels and that their financial prospects are dim, absent continuation of state and — especially — federal subsidies. This dominance by conventional energy industries is unlikely to change in the next decade, even if fossil fuel prices increase. However, there exist several niches in which alternative energy producers might be able to make money and thereby reduce energy imports. These take two forms: site-specific and region-wide.

At certain locations — a closed landfill, a city large enough to generate lots of waste wood, or at a manufacturing facility with substantial "waste" wood — feedstocks might be low enough in cost for local energy production to substitute for purchased energy or even to sell into the market.

Wood power, garbage power, and landfill gas power are location stories. They require local and cheap feedstocks, and these feedstocks are community or even site-specific. (Even though Minnesota has millions of acres of forest land, little of the wood that is harvested from these lands will be used for energy; paper, particle board, plywood, and dimension lumber plants will out-bid energy buyers whenever necessary.) We see no immediate prospects for widespread growth in these industries, although there are a few score closed landfills around the state that might be able to capitalize on small-scale generating technologies, especially if the problem of engine corrosion can be overcome.

For certain broader locations, wind energy profits will be sufficient to encourage investment in generation and distribution equipment — especially if the federal government continues to subsidize such development. Wind power is also a location story. Its expansion in Minnesota is clearly limited to those regions with sustained wind speeds at levels high enough to warrant the necessary investment in generating equipment. At some point, a region's electric power distribution capacity — designed as it was to get power into an area, not away from it — could prove insufficient. This is said to be increasingly the case in southwestern Minnesota. More efficient use of existing distribution capacity (through revamped contracts) and/or the construction of new distribution lines will be required if wind power is to increase in that region.

Ethanol and biodiesel production are price stories. There is an abundance of corn and soybeans in at least half of the state. The problem is that without the present high subsidy level, ethanol and biodiesel cost too much to make and deliver compared to petroleum products. Our budgets suggest that neither the ethanol industry nor the biodiesel industry could survive a substantial subsidy cut.

Alternative energy firms might be able to isolate themselves from conventional energy producers if they are able to convince consumers that some attribute of alternative power is worth paying extra for. Examples include attempts to market "green power" (essentially, a promise by utilities that a certain proportion of their supply comes from alternative sources) and the mandated (one way to express consumer preference) use of ethanol blended with gasoline. Overall, however, we think that alternative energy industries will continue to be forced to compete in the energy commodity markets. This means the industries will have to continue efforts to lower costs through technology development and to increase prices through subsidy and preferential purchasing. It is unlikely that alternative industries will expand in national markets by capturing load from conventional sources at current prices, but it might be able to replace imports (from outside Minnesota) and thereby increase its share of domestic (inside Minnesota) markets. The physical substitutability of biodiesel for petroleum-based diesel fuels is an example, although the financial substitutability of biodiesel is still in doubt, absent a dramatic decrease in biodiesel production cost or a similar increase in conventional diesel prices.

In the same way that many chemicals and other products are made from fossil fuels, in addition to just energy, it would be possible for the alternative energy industries to produce high value co-products that could improve the economics of the overall process. For example, a by-product of the biodiesel industry is glycerol. If a market were found for glycerol, the overall economics of the system would improve. A useful model is the wood products industry, which produces high-value products and energy from its waste. The energy product is not valuable enough to be produced alone. The production of high-value co-products seems to have potential mostly for the bio-based energy industries (wood, biodiesel, ethanol), although the production of hydrogen from wind power has also been discussed.

Some alternative energy industries in Minnesota might become competitive, in the sense that they will make money for investors under favorable price and policy scenarios, but none is likely to ever become "large," in the sense of gaining a substantial market share in the power or fuels markets. Conventional energy sources can and will supply most of Minnesota's demands for many years to come. Conventional sources have many attributes that are missing with alternative energy sources: they boast a set of proven, relatively low cost technologies; there has been substantial investment in the necessary supply and distribution infrastructure; they have reliable cost and performance data on which to base managerial decisions; they have a pool of human capital (experienced managers, operators, and investors) to draw upon; and they are supported by a long-lived set of direct and indirect subsidies that are not likely to be removed. Much of this technical and institutional infrastructure is only slowly emerging in the alternative energy industries.

Current Minnesota and U.S. policy supporting alternative energy consists of a mix of incentives, disincentives, research, and education. Having a mix is a reasonable strategy, but we think that the aggregate of these activities is too small and that the proportions of the ingredients is skewed because it relies too much on the government singling out particular resources or glamorous technologies for attention. We think it would be better if the government spent its scarce alternative energy investments on improving general market conditions and increasing the store of knowledge.

A major change in the economic environment for alternative energy would be higher taxes on conventional energy production, on the rationale that current prices are not fully reflecting true social costs of production, especially the pollution they cause. This approach has the advantage of not requiring the government to choose from among a set of untested technologies when deciding which alternative sources to support. Instead, the government would be required only to identify those attributes, such as pollution, that it did *not* want to support.

But substantially higher taxes on conventional sources of energy are politically unpopular, especially at a time when prices on all fuels are already rising dramatically. (Electricity prices do not yet show these rises.) Policies to encourage alternative energy production will instead have to focus on lowering the cost of inputs and reducing the costs of conversion.

Conclusion

The single biggest problem with alternative energy production is that we don't really know what we should do next. Advocates pull public attention from crop to crop, from technology to technology, from one concern about producers to another concern about consumers.

It's not a problem of technology. We can grow practically any crop, anywhere. We can make energy from practically any feedstock, any time. But we really don't know what these many underutilized feedstocks cost, and we don't know what we should charge for them.

An assessment of the efficacy of public investment is hampered by the requirements of business confidentiality. We don't know if our current policies are really "working," and we certainly have little public information on which to base sound public investment decisions in the future.

Even given this uncertainty, however, the following additions to the state's policy mix might improve the potential for alternative energy industries to improve local economic conditions.

1. *Establish a consistent reporting and tracking system*. There exists no agreed-upon list of alternative energy businesses in Minnesota. Worse, there is no agreement on the level of production or actual local economic impacts of individual firms or even the industry as a whole. This leaves decision makers in the dark.

2. *Reduce uncertainty in production and marketing*. The state needs to work with commodity exchanges and private consultants to increase the level of price and quantity information for alternative energy industries. There is broad public knowledge about soybean production and markets, for example, but there is essentially none for biodiesel production and markets.

3. *Continue to support research into new technologies that increase local development*. Both the state and federal governments support a modest level of research into alternative energy systems, especially in the development of new technologies. This should be increased, with an additional criterion for public investment. Research support should be weighted by the extent to which the proposed system promises to increase local, smaller-scale, dispersed energy production. There should also be a public disclosure requirement for all publicly supported research and development.

4. *Create conditions for creative energy markets*. Energy production and distribution has traditionally (and properly) analyzed and aggregated as a natural monopoly, an industry where economies of scale triumph over dispersed (local) development. This need not always be the case. One can imagine a different system in which common carriers, common meters, flexible contracts, and dispersed production supply energy consistently and at a relatively low cost. In such a system, local economic development might triumph over economies of scale.

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