System Implications of Distributed Generation: Economic and Environmental Externalities

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ABSTRACT

Distributed generation (DG) offers great potential for increased energy efficiency and CO_2 emission reductions. However for economic and environmental benefits, DG technologies require matching of heat to power ratios (HPR) to be utilized as cogeneration. This paper investigates how the potential benefits of DG translate to an integrated electricity and gas system. A cost optimization model selecting centralized-distributed and electricity-heat-cogeneration technologies is developed. The model minimizes overall cost of constructing and operating integrated electricity and natural gas networks and plants. Data is developed to compare system energy demands in two US states: New York (heat dominated) and Florida (electricity dominated). Particular attention is given to seasonal and HPR variability. Three results from the model are presented:

- Cost implications of DG vs. conventional supply
- Implications of DG for natural gas supply
- Implications of DG for pollutant emissions

Introduction

Distributed generation (DG) represents an alternative paradigm of energy generation and supply (Patterson 2000). This paper investigates the cost and externality implications for an integrated electric and heat system when DG technologies are available.

Gas-fired distributed generation (DG) is highly energy efficient (up to 95% HHV[1]) due to the cogeneration of electricity and heat and avoidance of electricity transmission losses. An emerging family of gas fired DG technologies have attracted considerable interest of policy makers for their potential to reduce CO_2 emissions (NREL 2000). IC engines are currently the most established gas-fired DG technology[2].

DG requires consistent electricity and heat demands (high utilization) to deliver economic and environmental benefits (Strachan 2000). However, variable demand for energy, and the need to balance generation and consumption imposes a load duration curve on utilities. This complicates the optimal mix of generation plants and delivery networks of electricity, gas and heat. There has been an ongoing debate concerning the system implications of DG, and who is compensated or penalized (Cogen Europe 1999).

Energy system analysis to meet variable demands at lowest costs and maximum reliability has a long history (e.g. Turvey and Anderson 1977). These studies have generally not included DG. Work that has investigated DG as an integral contributor of an energy

[1] Higher Heating Value. All efficiencies in this paper are quoted in HHV.
[2] As of 1998, IC engines of <1MWe accounted for 6% of Netherlands electrical capacity (i.e. 1,500 MWe).

system (Feinstein et al 1997), has focused on electricity-only applications, largely with a view to delaying investments in network infrastructure.

A cost optimization model is developed to investigate the optimal mix of technology plant and operating regimes to meet variable electricity and heat requirements at lowest overall cost. We focus on gas-fired technologies as we are interested in synergies between gas and electricity networks for electricity and heat provision. Within this framework, results presented here include:

- Cost implications of DG vs. conventional supply
- Implications for natural gas supply
- Implications for emissions of CO_2, SO_2 and NO_X

Integrated Electricity and Gas Cost Optimization Model

Model Overview

The model minimizes total investment and operating costs to meet seasonally varying power and heat requirements over a 15 year time horizon. The model assumes no initial plant and networks to compare optimal DG and conventional supply systems. A mixed integer linear program (MILP) selects fixed investments in energy technologies and their operation regime, from a variety of centralized-distributed and electricity-heat-cogeneration options. All technologies use natural gas for synergies in delivery networks. Longer lived capital assets are prorated with variable costs subject to a 10% discount rate. All costs are in US$ (2000).

The optimal technology mix depends not only on technology cost, but on demand seasonality and heat to power ratio (HPR) required. Energy demands are static over a 15 year time horizon and are based on residential, commercial and industrial consumption. Decision variables are integer numbers of energy plants and hourly operating regimes. Annual operating hours are broken down by season, and further divided by variable consumption demand times based on temperature. This approximates a load duration curve. We are particularly interested in extreme temperature variations as these are used for measures of peak electricity and heat demands. Plants are limited to 90% availability.

Optimization Equations

Table 1 summarizes the MILP optimization model to minimize total costs (C_T) of meeting electricity and heat requirements. The table lays out the components of the objective function, model indices, decision variables, demand constraints, and the energy outputs from each technology.

Table 1. Optimization Model Equations

	Equation	Explanation
Objective function	$\min(\sum_{j,q,b,j,i,k} C_{TOT}$ $C_{TOT} = (C_K + C_T + [C_{OM} + C_F])$	Minimize the cost of meeting variable electricity and heat demand
Indices	T	Time horizon (15 years). Pro-rated capital costs, all variable costs - discounted at 10%
	Q	Yearly season (summer, shoulder, winter)
	B	Temperature bands (hrs): max 1% (29hrs), high 9% (263 hrs), ave. 80% (2,336hrs), low 9% (263hrs), min 1% (29hrs)
	J	Technologies: power, heat or cogen
	I	Transmission network: elec, gas & heat
	K	Demand: residential, commercial, industrial
Costs	$C_K = \sum_{j}(K*\#*X,Y)$	Capital costs of technologies: K is cost per kW, X is electrical capacity, Y is heat capacity, and # is number of plant
	$C_T = \sum_{j,i}(T*\#*X,Y)$	Cost of energy transmission for electricity, gas and heat: T is trans. cost per kW
	$C_{OM} = \sum_{j,b,q,t}([OM_1+(OM_2*h)]*\#*X,Y)$	OM_1 is O&M cost per kW, OM_2 is O&M cost per kWhr, h is hours run
	$C_F = \sum_{j,b,q,t}(F*h*\#*[X,Y/E])$	Fuel cost (natural gas): F is fuel cost per input kW, E is plant efficiency
Decision variables	#	Number of plants (integer)
	H	Hours run
Demand constraints	$\sum_{j,t,q,b,k}(X*\#*h) \geq Qe(b)$	Meet or exceed electrical demand (Qe) each period (variable by temp. and season)
	$\sum_{j,t,q,b,k}(Y*\#*h) \geq Qh(b)$	Meet or exceed heat demand (Qh) each period (variable by temp. and season)
Electricity output	$Qe = \sum_{j,b,q,t,k}(L*G*X*\#*h)$	Where L and G are electricity and gas transmission efficiencies
Heat output	$Qh = \sum_{j,b,q,t,k}(H*G*Y*\#*h)$	Where H is heat transmission efficiency
Additional constraints	$h(b,j) \leq h(\max b)$	Plant operating hrs less than hrs per period
	$A(j) \leq 7884$	90% plant availability
	$h \geq 0, \# \geq 0$	Non negativity constraints
	$\#(j) = \text{integer}$	Number of plants must be an integer value

Model Parameters

Inputs[3]

Table 2 details the energy technologies the optimization model can choose by size range and energy output. These technologies represent the current convention of larger scale electricity generation and smaller scale on-site heat production. Cogeneration technologies are available in all size categories.

[3] A source list of data input can be given on request

Table 2. Energy Technologies in Optimization Model

	Centralized (>100MW)	Intermediate (1-50MW)	Distributed (100kW - 1MW)	Micro Distributed (5kW-100kW)
Electricity only	Combined cycle gas turbine (CCGT)	Gas turbine (elec)		
Heat only			Large boiler	Small boiler
Cogeneration	Steam turbine	Gas turbine	Engine	Micro-engine

Table 3 summarizes the costs of our various technologies in per kW and per kWhr terms, to enable comparison between technologies of such variety of sizes.

Table 3. Optimization Model Sample Parameters

Technology	Units	Steam turbine	CCGT (elec)	Gas turbine	GT (elec)	Engine	Micro-engine	Large boiler	Small boiler
Capital cost	\$/kWe	600	550	500	400	700	1000	200	300
O&M cost	¢/kWh	0.7	0.85	0.85	0.7	1	1.5	0.4	0.5
Gas price	¢/kWh	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Lifetime	years	30	30	20	20	15	15	20	15
Capital cost recover in 15 yrs	\$/kWe	497	456	459	367	700	1,000	184	300
Electricity transmission cost	¢/kWh	1.88	1.88	0.77	0.77	0.24	0	-	-
Gas trans. cost	¢/kWh	0.04	0.04	0.13	0.13	0.44	0.66	0.44	0.66
Heat trans. cost	¢/kWh	1.32	-	0.88	-	0.26	0	0.26	0
Elec. network efficiency	%	91.7%	91.7%	95.8%	95.8%	100%	100%	-	-
Gas network efficiency	%	99.3%	99.3%	99.0%	99.0%	98.7%	98.7%	98.7%	98.7%
Heat network efficiency	%	80.8%	-	94.3%	-	98.1%	100%	98.1%	100%
Plant efficiency	%	36%	55%	34%	34%	29%	26%	92%	90%
Maximum HPR	#	1.5	-	1.65	-	2.1	2.5	-	-
Electrical Size	kWe	500,000	100,000	10,000	10,000	500	10	-	-
Heat Size	kWth	750,000	-	16,470	-	1,050	25	500	25

Data on capital costs, O&M costs and plant efficiencies vary by source. Differences include site specific nature of costs (particularly for larger generating plant), financing and ownership structure, and base vs. peak operation for per kWh costs. Cogen plants generally entail higher capital and O&M costs due to additional components (heat exchangers etc).

Transmission costs for electricity, gas and heat networks entail the same estimation problems as capital and O&M costs. System design and the quantity of energy to be transferred are especially important. The model estimates costs using the difference in energy prices (EIA 1999) from centralized to intermediate to distributed energy users as a bound on the costs of transmission. A linear adjustment of transmission costs due to demand density is used as an approximation. Natural gas network losses are much less than electricity transmission. There is a scale limit on heat transfer and utilization. Limits on heat transfer are modeled using heat transfer efficiency and availability of heating load for different sizes of technologies.

Natural gas prices used in the model are representative, especially considering recent price volatility. Gas prices[4] are wellhead gas prices with transmission costs to user categories factored in separately. Therefore, smaller technologies will have higher gas purchase costs. Sensitivity analysis on gas prices is discussed in section 4.2.

Seasonal Demand

Seasonality of demand is crucial in selecting an optimal technology mix as variable electricity and heat requirements result in low load factors for plants and especially poor conditions for economic savings from cogen plants. New York and Florida are used as units of analysis with energy requirements dominated by either heat or electricity.

Industrial demand is considered to be consistent through the year. For the residential and commercial sectors, seasonal components are air conditioning and space heating. Water heating and appliances constitute the base energy load. Figure 1 shows the temperature bands per season for each State. We consider cooling is required if temperatures exceed 70°F and heating is required is temperature falls below 65°F.

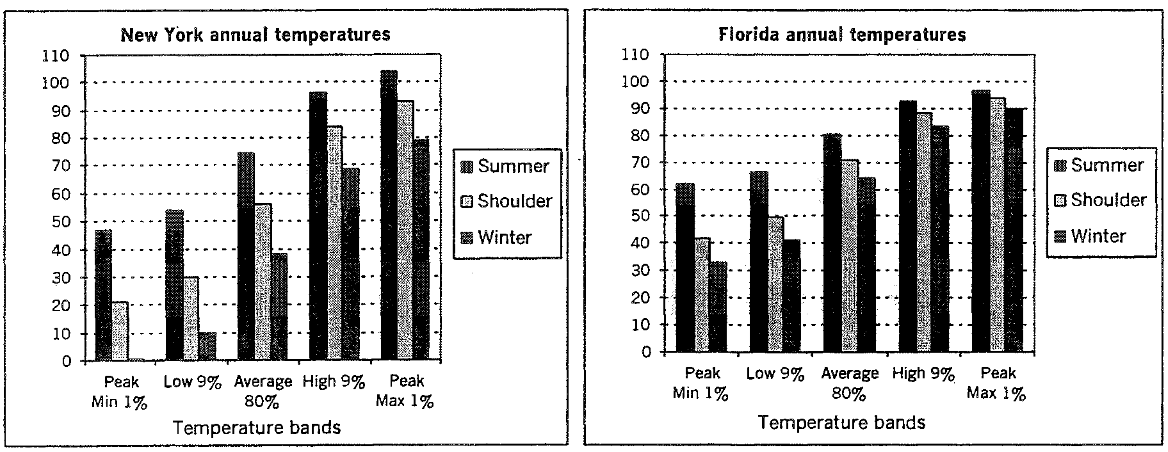

Figure 1. New York and Florida Temperature Distributions

The following steps translate these temperature distributions into energy requirements for the residential and commercial sectors.

1. Calculate the proportion of seasonal vs. base-load demands using State energy consumption data, and residential and commercial buildings energy surveys.
2. Partition the annual variable demands into seasonal averages (in GWhrs) using State degree day data on a monthly basis.
3. Calculate the required heating or cooling hours per temperature band using the temperature distributions relative to heating (65 F) and cooling (70 F) standards.
4. Derive the electricity and heat load per hour (in GWe,th) by dividing the seasonal proportions of electricity and heat requirements by the hours per temperature band.

[4] To convert from ¢/kWh (of input fuel energy, as conversion efficiencies are factored in later in the model) to \$/m cu.ft. for gas, use 1kWh=3.6MJ, natural gas has 39.1MJ/m^3, and 1m^3 = 35.3cu.ft. Thus 1 ¢/kWh = 3.08 \$/MCF. of gas. Thus for our model values: 0.89 ¢/kWh for natural gas = 2.74 \$/MCF.

5. Combine with non-seasonal base-load to approximate the load duration curve, paying particular attention to peak energy requirements.

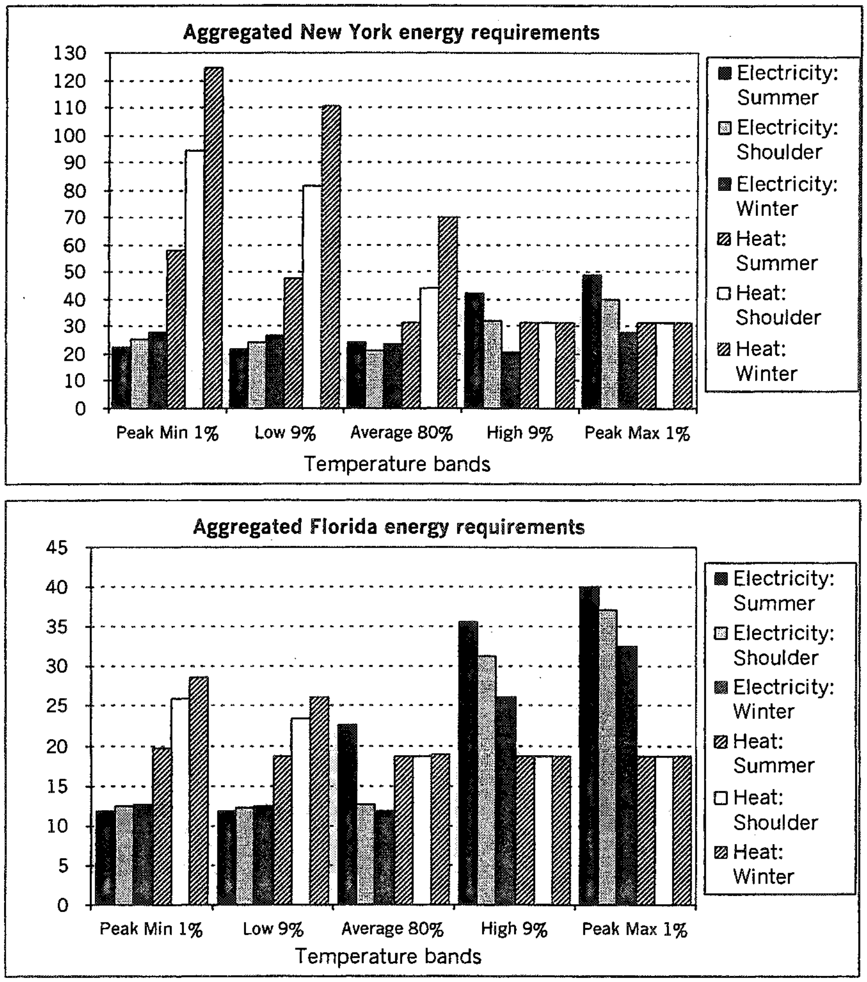

Figure 2. New York and Florida Electricity and Heat Requirements

Aggregated energy demands in GWe,th are given in Figure 2 for New York and Florida. New York has much larger relative heat demands in winter/coldest temperature bands, together with some electric heating. In addition, New York's energy demand has more variability. Florida has relatively greater electricity demands in summer/warmest temperature bands.

Model Results

Cost Implications of Distributed Generation vs. Conventional Supply

For a private investor, the lowest cost technology is DG based on IC engines, provided that consistent electricity and heat load are available. By restricting the technologies available to the model, optimal system solutions using DG can be compared to an energy system using conventional electricity-only and heat-only technologies.

Using the aggregated demands for New York and Florida, Table 4 gives the technology choice and overall costs when using electricity or heat-only technologies, when allowing progressively smaller cogeneration technologies, and lastly when allowing DG.

Table 4. DG, Cogeneration and Conventional Supply Solutions: New York and Florida

NEW YORK	Technology choice and use	Optimal cost (M$) (and savings)
No cogen technologies at all	Electric base-load: 33 CCGTs, peak electric needs: 4,830 gas turbines, heat needs: 256,180 large boilers	183,410
None of micro-engines, engines, cogen gas turbines	Base-load: 56 steam turbines, peak electric needs: 2,460 gas turbines (elec), peak heat needs: 189,050 large boilers	169,880 (7.4% decrease)
None of micro-engines, engines	Base-load: 5,150 cogen gas turbines, additional heat: 89,080 large boilers	149,040 (18.7% decrease)
No micro-engines	As above	135,340 (26.2% decrease)
ALL	Base-load: 98,930 engines, additional heat: 4,430 large boilers	135,340 (26.2% decrease)
FLORIDA	**Technology choice and use**	**Optimal cost (M$) (and savings)**
No cogen technologies at all	Electric base-load and peak: 4,210 gas turbines, heat needs: 5,880 large boilers	97,730
None of micro-engines, engines, cogen gas turbines	Base-load: 32 steam turbines, peak electric needs: 2,670 gas turbines, peak heat needs: 19,198 large boilers	92,750 (5.1% decrease)
None of micro-engines, engines	Base-load: 1,860 gas turbines (cogen), additional electricity: 2,350 gas turbines	80,280 (17.9% decrease)
No micro-engines	Base-load: 28,046 engines, additional electricity: 2,745 gas turbines	77,120 (21.1% decrease)
ALL	Base-load: 28,040 engines, additional electricity: 2,750 gas turbines, 1 micro-engine for residual	77,110 (21.1% decrease)

Savings due to DG and cogeneration are substantial compared to conventional energy supply. As the available size of the cogeneration technology gets smaller, savings increase, owing both to the improved costs of gas turbines and then IC engines, and also as these smaller units can be used more flexibly to meet variable load. Use of DG results in system cost savings of 26.2% and 21.1% in New York and Florida. New York realizes higher percentage cost savings from DG than Florida as its greater heat demand allows the large heat output from IC engines to be utilized. Florida's large electricity requirements ensure electricity-only gas turbines remain a significant part of the generating capacity.

Sensitivity analysis has been undertaken on capital costs, O&M costs, natural gas prices (section 4.2), electricity and gas transmission costs and discount rates over different optimization time-frames. The economic benefits of DG for an energy system appear robust over a reasonable range of parameters.

Implications for Natural Gas Usage

The comparison of the optimal DG and conventional supply solutions is extended to annual natural gas usage. Both the overall use of gas and seasonal variations are of interest. Table 5 shows the annual gas usage in billion cubic feet for electricity or heat-only technologies, when allowing progressively smaller cogeneration technologies, and lastly when allowing DG, and compares this with total costs (in M$ over 15yrs), for New York and Florida.

Table 5. Annual Gas Usage of New York and Florida

	NO cogen technologies	NO cogen engines, GT, ST	NO cogen engines, GT	NO cogen IC engines	DG solution
New York					
Annual gas use: Bcu.ft.	283.5	208.8	203.9	210.6	210.6
% decrease	-	26.3%	28.2%	25.7%	25.7%
Total cost (M$)	183,910	169,880	149,040	135,340	135,340
% decrease	-	7.4%	18.7%	26.2%	26.2%
Florida					
Annual gas use: Bcu.ft.	164.6	120.2	118.1	124.9	125.1
% decrease	-	27.0%	28.3%	24.1%	24.0%
Total cost (M$)	97,720	92,750	80,280	77,120	77,110
% decrease	-	5.1%	17.9%	21.1%	21.1%

For this gas-fired system, any fuel use variation is due to system-wide efficiencies of generation and transmission of electricity, gas and heat. For both New York and Florida, DG technologies save around a quarter of natural gas requirements (25.7% and 24.0% respectively) compared to conventional supply technologies. Using larger cogeneration technologies, gas use is actually slightly less than the DG solution. This is because larger cogen technologies have a higher electrical efficiency, allowing cogen units to better meet electrical needs. This is more evident in the case of Florida with its proportionally larger electrical requirement. When cogen steam turbines are employed, their higher electrical efficiencies begin to be balanced out by greater transmission losses, especially heat transfer.

Figure 3 shows the seasonal savings of gas in New York and Florida using DG in the optimal solution. The DG solution reduces gas demand throughout the year (i.e. in high and low heat demand times). However the amount of reduction varies by period.

The maximum gas savings occur when demand HPR is closest to HPR of DG technology used (i.e. HPR=2.1, using IC engines at 29% efficiency). When HPR is low, either higher cost electricity-only plant is used, or heat from the cogen units is dumped. Similarly during high HPR times, excess electricity is produced by the cogen units. It should be noted that DG saves natural gas even at the highest heat demand periods when the requirements on a gas network are most stringent. This 12% reduction (at HPR=4.4) frees up capacity in the gas pipeline system.

Percentage savings of gas are relatively higher (per HPR) for the Florida case. Florida's optimal solution contains cogen, heat-only and electricity-only technologies, and can thus better match HPR variation especially at low HPR where using cogen to meet electricity demand would involve heat dumping.

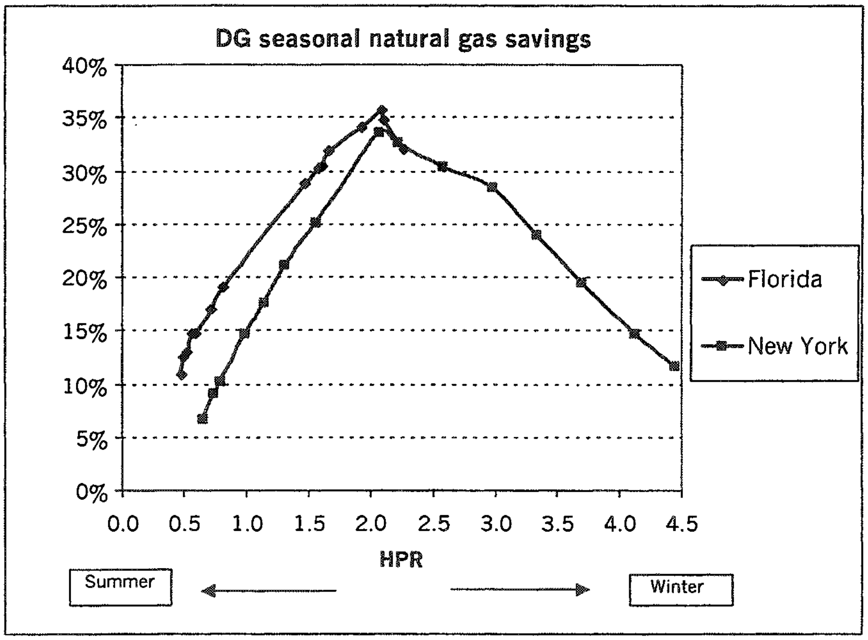

Figure 3. Seasonal Gas Usage for New York

DG reduces overall natural gas use. However, recent gas price hikes in the US (doubling from \$2.7/MCF to \$5.4MCF), may impact the cost attractiveness of DG. At a gas price of \$2.7/MCF, base-load IC engines account for 33.8% of electrical capacity and 54.0% of generation with peaking electricity gas turbines at 66.2% of capacity and 46% of generation. The limit on IC engines is the available heat load. Using the doubled gas price of \$5.4/MCF in this gas-fired system, the share of IC engine remains constant, with CCGT plant being introduced (19.7% of generation) and gas turbines falling to 26.8%.

If the model is allowed to select coal steam turbines to produce electricity (with coal at 0.42¢/kWhr or \$29/short ton), IC engines remain at 53% of electrical generation and meet all the heat load. The coal steam turbines meet 41.9% of generation with gas turbines at 5.1% and micro-engines at 0.5%. Only when cogen coal-fired steam turbines are allowed does DG lose its base-load operation, being restricted to 0.4% of generation with coal steam turbines at 84.7% and gas turbines at 14.9%.

Implications for Pollutant Emissions

A final comparison between the optimal DG and conventional supply solutions is made for emissions of CO_2, SO_2 and NO_X. Output emissions are compared and converted into social costs using shadow prices.

Shadow prices for CO_2, SO_2 and NO_X emissions are taken from (Matthews and Lave 2000, Oak Ridge National Laboratory 1995). Emission factors per technology for CO_2 and SO_2 (from above references) depend only of the efficiencies of plant and network, and the content of carbon and sulfur in the fuel used. For SO_2 savings the optimal gas-fired technology mix is compared to conventional supply with coal-fired steam turbines. NO_X

emissions depend on operating methodology and control technology. NO_X emission factors are taken from (STAPPA and ALAPCO 1994). IC engines and micro-engines can be controlled for NO_X using catalytic converters. Table 6 summarizes shadow prices and output emission factors.

Table 6. Shadow Prices and Emission Factors for Pollutants

	CO_2	SO_2	NO_X
Shadow prices: $ / kg	0.017	1.80	1.08
Emissions per output unit: kg / MWhr			
Steam turbine	500	-	1.05
CCGT	327	-	0.78
Gas turbine	500	-	0.18
Engine (NO_X non-control)	621	-	10.00
Engine (NO_X control)	621	-	1.00
Boiler	200	-	0
Coal steam turbine	900	5.2[5]	1.70

Figures 4 and 5 give annual emissions and emissions costs for New York using DG, gas-fired conventional supply, and conventional supply with coal-fired centralized plant. Natural gas reductions translate into comparable savings of CO_2. These are increased if coal steam turbines are included. Coal steam turbines also produce high SO_2 emissions and costs. Engine NO_X emissions can be controlled by an order of magnitude but still give an increase in NO_X compared to conventional supply. However, coal steam turbines produce higher NO_X emissions than controlled engines (due to fuel NO_X from coal).

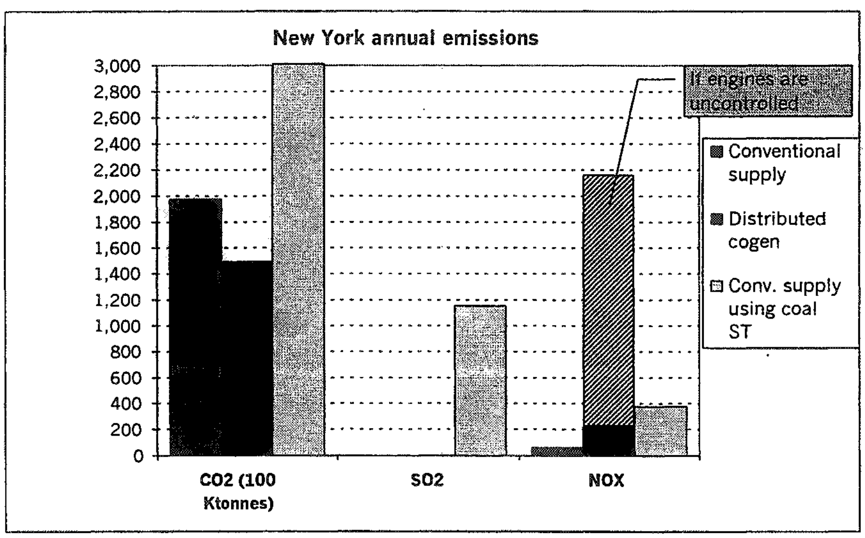

Figure 4. Annual Pollutant Emissions for New York

[5] SO_2 emissions of 5.2 kg/MWhr (output measure) corresponds to 1.2lbs/MMBTU (input measure). This is the Clean Air Act standard for US plants in year 2000.

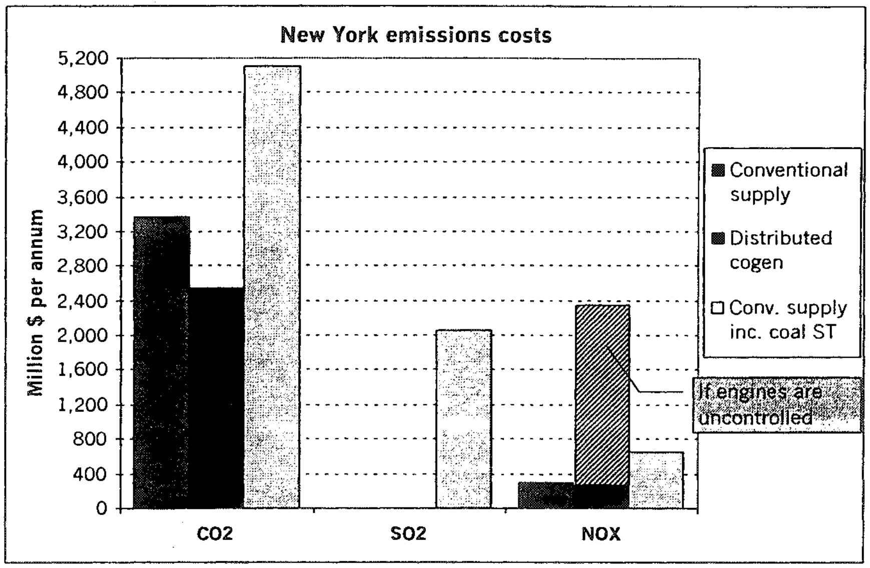

Figure 5. Annual Emission Costs for New York

It is noted that a simple summation of pollutant externalities does not account for spatial and temporal characteristics of local air pollutants.

Conclusions

A 'green-field' cost optimization model was developed for the electricity and natural gas systems of two US states with very different seasonality and HPR characteristics. Temperature data was translated into variable energy demands. Centralized-distributed and electricity-heat-cogeneration technologies were available, with technologies being gas-fired to investigate synergies in energy networks.

Given that DG technologies (IC engines) were the lowest cost technologies, the optimal solution including DG was compared to a system using conventional electricity and heat-only plant. DG cost savings are substantial, at about 26% for New York and 21% for Florida. New York realizes higher percentage cost savings than Florida as its greater heat demand allows the large heat output from IC engines to be better utilized. Therefore, the cost savings of DG apply to an integrated electricity and natural gas system.

Extending the DG vs. conventional supply comparison to natural gas usage, the greatest reductions are when demand requirements match the outputs (i.e. HPR) of the DG technologies. In the cases of New York and Florida, average loads which constitute 80% of total requirements are a good HPR match, which results in overall natural gas savings from DG of 26% and 24% respectively. Peak demand requirements are less well matched, although with DG technologies overall gas demand is always reduced.

Sensitivity analysis finds that DG is still favored in Florida for cogen base-load even with a doubling of gas prices to reflect recent market trends. The overall efficiency of gas-fired DG is an improvement over the combination of CCGT and heat-only boiler plant. If the model can select coal fired steam turbines, these units must be operated as cogen plants to erode the market share of DG.

The comparison was further extended to look at social costs from emissions of CO_2, SO_2 and NO_X. Employing pollutant shadow prices, the DG solution (catalytically controlled) delivers CO_2 savings with only a small increase in NO_X emissions. Considering coal steam turbines in the conventional supply mix, these further increase CO_2 and NO_X emissions, and also have sizable SO_2 emissions. Aggregating social costs from pollutant emissions increases the monetary savings of DG to meet a system's electricity and heat requirements.

Future work focuses on technical, economic and regulatory factors that will impact any transition to distributed generation (DG), including consideration of existing energy plant and networks.

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