04-CCCA-1

Symbiotic Strategies, LLC

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#35088

DOCKET
04-IEP-1B
DATE JUL 22 2005
RECD. JUL 26 2005

July 22, 2005

California Energy Commission
Dockets Unit
Attn: Dockets **04-CCCA-1** and **04-IEP-1B**
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: • Docket **04-CCCA-1**, Climate Change Advisory Committee
• Docket **04-IEP-1B** and Climate Change
• 2005 Integrated Energy Policy Report and Climate Change –Workshop – July 12, 2005

Dear Sirs:

On behalf of my client Primary Energy and in the interest of using energy far less wastefully and more cleanly in California and the nation, I am pleased to submit the accompanying materials in support of the California Energy Commission's efforts in the above-referenced dockets and report. Primary Energy thanks the Commission for the opportunity for Mr. David Hermanson, General Manager of West Coast Operations, to appear before the Commission at its July 12, 2005 workshop in the above referenced docket.

Headquartered in Oak Brook, Illinois with combined heat and power (CHP) distributed generation (DG) facilities in San Diego and Oxnard, California, Primary Energy specializes in recycling waste energy to produce clean and affordable heat and power. Recycled energy is (1) electricity or steam produced from exhaust heat from any commercial or industrial process; (2) waste gas or industrial tail gas that would otherwise be flared, incinerated or vented; and (3) electricity or equivalent mechanical energy extracted from a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat. Sited at host facilities, recycled energy is always distributed generation, thus reducing line losses and enhancing system reliability and security. Moreover, recycled energy generally requires no additional fuel, creates no additional emissions, and helps host manufacturers become and remain more competitive. The attributes, applications, and opportunities associated with recycled energy are detailed much more fully in the attached materials, principally authored by Primary Energy's Chairman and CEO, Thomas R. Casten.

Primary Energy has identified at least 1,600 MW of waste energy capacity in California, though due to poor data availability, the true capacity is likely to be significantly higher. If fully utilized, this capacity could contribute approximately 8% of the Governor's 2010 greenhouse gas emission reduction goals – while enhancing California's economy. The multiple benefits of recycled energy to California's citizens, economy, and environment warrant particularly favorable treatment for such installations in the Preferred Loading Order and/or through inclusion in other incentive programs, such as classification as RPS-certified and SEP-eligible facilities.

Primary Energy commends the Commission for opening these challenging but crucial dockets, and looks forward to assisting in any way we can. Please contact me at 617-784-6975 or kcolburn@nescaum.org if you have any questions or would like additional information.

Sincerely,

Kenneth A. Colburn

Kenneth A. Colburn

Attachments:

- Hermanson, David J., Increasing California's Energy Efficiency: Recycled Energy and CHP, PowerPoint presentation to the California Energy Commission, July 12, 2005.
- Casten, Thomas R., Adding Recycled Energy to Advanced Energy Portfolio Standards, April 19, 2002.
- Casten, Thomas R., and Brennan Downes, Economic Growth and the Central Generation Paradigm, USAEE *Dialogue*, August 2004.
- Casten, Thomas R., and Brennan Downes, Critical Thinking About Energy: The Case for Decentralized Generation of Electricity, *Skeptical Inquirer*, January-February 2005.
- Casten, Thomas R., Energy Recycling: The Missing Link, *Power & Energy Continuity*, March 2004.
- Casten, Thomas R., and Martin J. Collins, Recycled Energy: An Untapped Resource, April 19, 2002.
- Bailey, Owen and Ernst Worrell, Clean Energy Technologies: A Preliminary Inventory of the Potential for Electricity Generation (in Draft), LBNL, July 2004.

Integrated Energy Policy Report Committee and Climate Change Advisory Committee

July 12, 2005

Increasing California's Energy Efficiency: Recycled Energy and CHP

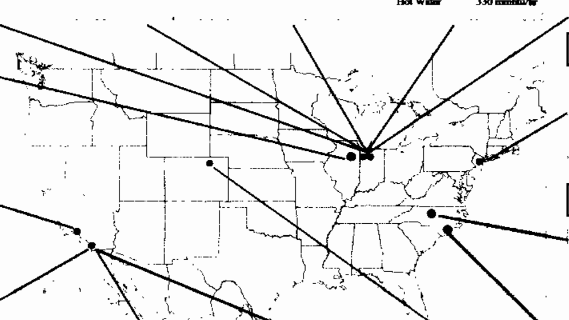
David J. Hermanson

General Manager, West Coast Operations

Primary Energy, LLC

Primary Energy

Primary Energy Overview



North Lake

Customer	Mittal Steel
Ownership	100%
Capacity	75 MW

Ironside

Customer	Mittal Steel
Ownership	100%
Capacity	
Electric	50 MW
Steam	460 mlbs/hr

Harbor Coal

Customer	Mittal Steel
Ownership	50%
Capacity	
Pulverized Coal	110 tons/hr

Portside

Customer	U.S. Steel
Ownership	100%
Capacity	
Electric	63 MW
Steam	500 mlbs/hr
Hot Water	330 mmbtu/hr

Cokenergy

Customer	Mittal Steel
Ownership	100%
Capacity	
Electric	94 MW
Steam	930 mlbs/hr

Oak Brook, HQ

Kenilworth

Customer:	Schering Plough, JCP&L
Ownership	100%
Capacity	30 MW
Steam	380 mlbs/hr

Oxnard

Customer	SoCal Ed, Boskovich Farms
Ownership	100%
Capacity	49 MW
Steam	120 mlbs/hr

Roxboro

Customer	CP&L / C&A
Ownership	100%
Capacity	
Electric	60 MW
Steam	120 mlbs/hr

Naval Station

Customer	U.S. Navy, SDG&E
Ownership	100%
Capacity	48 MW
Steam	387 mlbs/hr

Southport

Customer:	CP&L / ADM
Ownership	100%
Capacity	120 MW
Steam	240 mlbs/hr

North Island

Customer	U.S. Navy, SDG&E
Ownership	100%
Capacity	40 MW
Steam	390 mlbs/hr

Naval Training Center

Customer	US Navy, SDG&E
Ownership	100%
Capacity	25 MW
Steam	285 mlbs/hr

Greeley

Customer	UNC, Xcel
Ownership	100%
Capacity	75 MW
Steam	285 mlbs/hr

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Overview

California wants:

1. A reliable electric system
2. A more competitive economy and ability to retain good, in-state jobs
3. A cleaner environment with less pollution and reduced GHG emissions

Recycled Energy (RE) meets these goals...

Primary Energy

What is Recycled Energy (RE)?

Recycled Energy

- Substitutes ***knowledge*** and ***capital*** for ***fuel***, making productive use of another's waste energy
- Takes advantage of waste energy through:
  - Waste Heat Recovery
  - Capture and combustion of off-gases
  - Capture and use of pressure changes
- And uses it to generate electricity, steam, or chilling
- *... Really just increasing energy efficiency*

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California Wants:
1. A Reliable Electric System

Recycled Energy:

- Creates more supply with no additional fuel
- Is always distributed generation, so reduces grid congestion
- Provides greater energy security because generation is dispersed
- Is not intermittent (reserve capacity not needed)
- Minimizes T&D losses, expansion, and investment
- Can provide backup power to the grid in emergencies

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California Wants:
2. A More Competitive Economy

Recycled Energy:

- Generates more power with no additional fuel
- Reduces fuel demand and lowers peak power loads, reducing costs for everyone
- Improves industrial competitiveness through lower energy costs
- Hosts are typically manufacturers with good high-paying jobs
- Helping the manufacturing core in turn helps to retain surrounding businesses

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California Wants:

3. A Cleaner Environment and Lower GHG Emissions

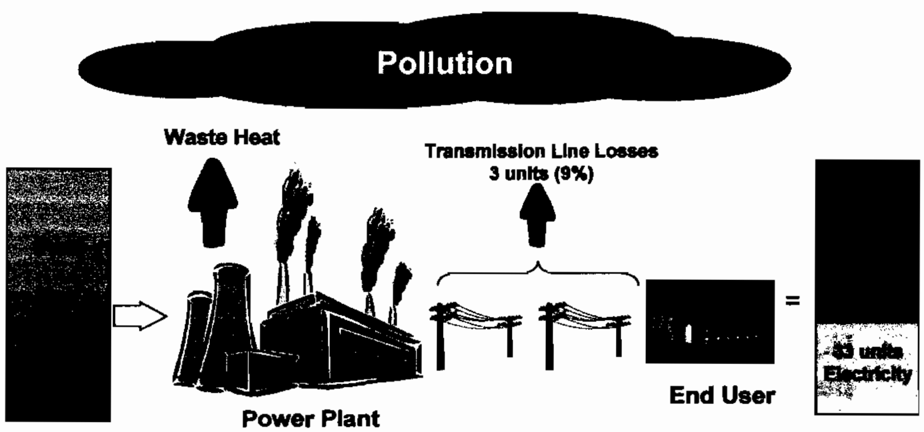
Recycled Energy:

- Squeezes more work out of fossil fuels being consumed
- Creates no additional emissions
- Requires less "single-use" central generation, reducing corresponding emissions
- Reduces generation needed to compensate for line losses (and its fuel costs & emissions)

Primary Energy

Historical Approach to Generation:

Conventional Central Station



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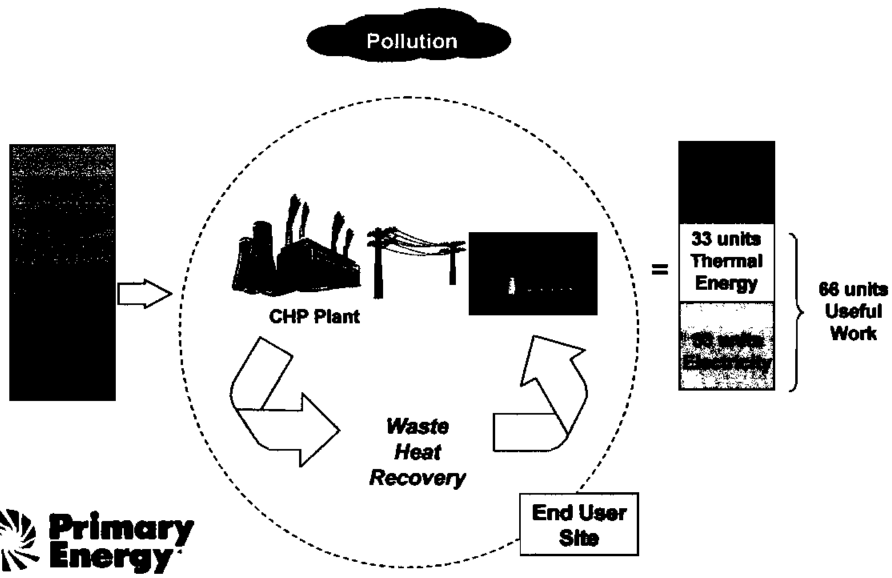
California's Best Efficiency Improvement:
Recycled Energy / Combined Heat & Power



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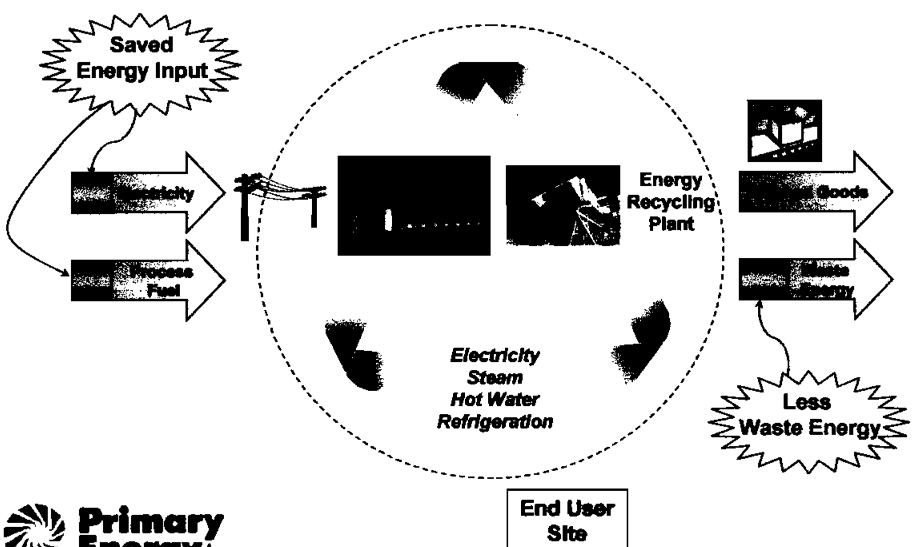
Recycled Energy Options



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CO_2 Emissions & Energy Policies

CO2 Emissions	=	Carbon Content of Fuel	x	Amount of Fuel Used
		Focus: Renewables		*Focus: Efficiency*

- California has worked hard to reduce *Carbon Content*
  - RPS, Supplemental Energy Payments, Loading Order, etc.
- But what have we done to reduce the *Fuel Used*?
- We should adopt an *Energy Efficiency Portfolio Standard* or other *RPS-like requirements* to reduce the *Amount of Fuel Used* through measures like RE?

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Does California have RE potential? *YES!*

- Across many industries (glass, chemicals, refining, food processing, industrial boilers, electricity, etc.)
  - Waste Heat Recovery & Industrial Off-gases (EPA) – 961 MW
  - Pressure Drops / NG Expanders (EPA) – 124 MW
  - Oil Production (pumping) (COPE) – 400-600 MW
  - *Understated due to little reporting outside power plants*
- 1600 MW of RE would offset CA power sector emissions:
  - CO_2: ~ 6.6% NOx: ~ 6.5%;
  - SO2: ~6.5% Mercury: ~3.2%

  (Almost 3 times more if offsetting out-of-state coal power)
- *RE could achieve ~8% of CA's 2010 GHG target alone!*

Primary Energy

Why Aren't We Doing More RE Now?

- Optimal Choices Blocked by "Conventional Wisdom":
  - "All power must flow through wires"
  - "Central generation provides economies of scale"
  - "Exit fee burdens are created by new technologies"
  - "Fixed costs increase for remaining customers"
    - Despite state-wide load growth?
- Often Manifest as Regulatory Obstacles
  - No Standard Offer Contracts
  - Punitive Standby Rates
  - Exit Fees
  - Discount rate retention deals
  - No incentives/requirements for efficiency like for renewables (e.g., RPS or SEPs)
- *Result: Management focuses on core business, not readily available energy opportunities*

Primary Energy

California Has a Win/Win Leadership Opportunity

- Modest energy policy changes can induce optimal choices:
  - Lowering energy costs, fossil fuel use, and emissions
  - Increasing energy security and manufacturing competitiveness
- Changes should include:
  - End of central generation as the default paradigm
  - Modernize obsolete rules that create barriers to efficiency
  - Fix environmental rules to reward efficiency
  - Reward all players for efficiency

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What Should CEC, CPUC and CalEPA do?

- ***"Avoiding high costs later requires accounting for CO2 in current investment decisions and technology choices."***

  The U.S. Electric Power Sector and Climate Change Mitigation, **Pew Center on Global Climate Change, June 2005**

- **History proves mandates are needed to drive innovation and technology development...**
- **So, we need an "energy efficiency mandate"**
- **Don't pick technologies, but create the obligation**
- **Incorporate incentives, like factoring efficiency into Loading Order**
- **Reinstate Standard Offers to help in financing**

Primary Energy

Bottom Line:
RE and CHP Can Bring Immediate Benefits to California

- **More power with less fuel**
- **Cleanest power possible – *no incremental emissions***
- **Distributed for greater reliability and energy security**
- **Non-Intermittent energy supply**
- **Little T&D investment; minimal line losses**
- **Makes California manufacturers more competitive**
- **And importantly, no unintended consequences!**
  - **California's innovative energy policies have sometimes produced *unintended results...***
  - **But more RE and CHP just makes California more efficient**

Primary Energy

Thank you for listening!

Primary Energy

New Heat Recovery data

Sum of Power Available from Heat Recovery (MW) by County

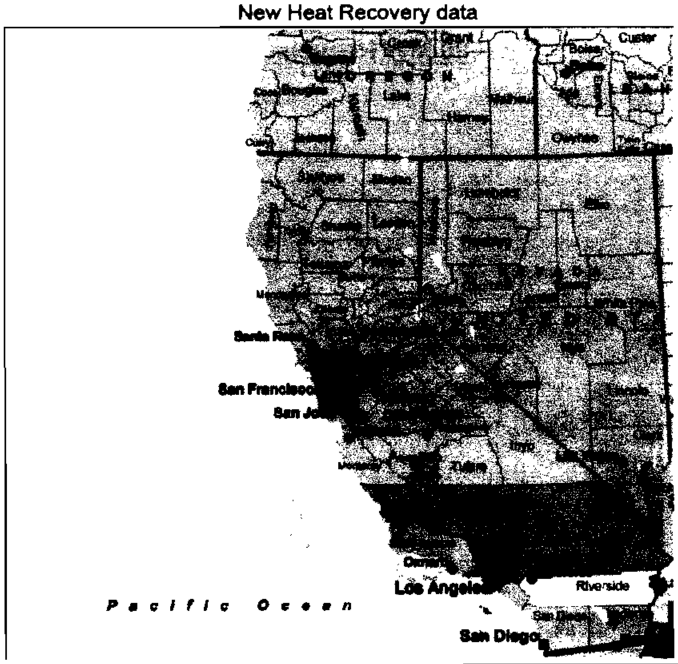
900

13

0.2

Pushpins

US stack info small file new



Recycled Energy Case Study: Primary Energy

- We invested $300 million to recycle blast furnace and coke oven exhaust in four steel plants, creating:
  - 440 megawatts of electric capacity
  - 1.8 million pounds/hour of steam capacity
- Steel mills save over ***$100 million per year***
- Primary Energy makes a fair return on capital
- CO_2 reduction is equivalent to one million acres of new trees.

Primary Energy

Primary Energy's View of The Future
90 MW Recycled from Coke Production

Capital Costs per Kilowatt:
Central vs. Decentralized Generation

	Generation	Transmission & Distribution	Total / kW of Generation	KW required/ kW Load	Total costs/ kW New Load
Conventional Central Generation	$890	$1380	$2,270	1.52	$3,450
Decentralized Generation	$1,200	$138	$1,338	1.07	$1,432
Savings (Loss) of Local vs Central Generation	($310)	$1,242	$1,068	0.47	$2,018
% of Central Generation	(34%)	90%	47%		59%

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Adding Recycled Energy to Advanced Energy Portfolio Standards

Executive Summary

Governments in the US and other developed countries have encouraged deployment of pollution free electric production by imposing Renewable Portfolio Standards, (RPS) or Advanced Energy Portfolio Standards, (AEPS). In general, these laws require a rising percentage of electric power delivered by regulated utilities to be generated by those technologies the law considers clean. The lists of clean technologies nearly always include power from solar energy and wind, and then selectively add power from biomass and/or small hydroelectric generation. Some laws include power from fuel cells, even though they consume fossil fuel. The laws create separate markets for the types of clean power included in the definition, thus providing an added revenue stream to developers of cleaner energy production. The first order impact of such laws is to increase the prices paid for electricity, and to decrease the pollution associated with electricity production. At issue is whether this is the least expensive way to reduce pollution, and whether the benefits will equal or exceed the costs.

The ensuing debates have pitted environmentalists, who feel government must intervene to force industry to a sustainable energy system, against capitalists/economists/policy makers who seek least cost energy. Proponents of portfolio standards insist that the markets are filled with barriers, that the costs imposed on present and future society by excessive pollution are not reflected in market signals and thus the government should intervene with mandatory standards. Opponents object to mandates, and insist that the current market optimizes power generation, so any government mandates will inevitably hurt the economy. Those debating appear to have no common ground, leading to portfolio standards being enacted when environmentally minded voters outnumber economically minded voters.

This article explains another class of clean energy, recycled energy, and contends that Advanced Energy Portfolio Standards that include all potential clean energy generation, including recycled energy, have strong potential to reduce pollution and reduce the total cost of energy production. Three major types of recycled energy are defined and examples given, total potential is analyzed by state in the US. Recycled energy uses the energy content of flared gases, wasted exhaust heat and unused gas pressure drop to generate electricity. Both in terms of the economic value of otherwise wasted energy and the environmental consequences resulting from such wasted energy, recycled energy represents a significant untapped resource. Finally, language is suggested that could be included in existing and future RPS or AEPS rules to improve results.

Recycling Waste Energy — A Primer

Many industries apply large quantities of energy to melt, distill, shape, or otherwise transform raw material into more finished products, and then discard high quality energy as waste, after only one use. The wasted energy emerges in three forms; as low-grade gas that is flared, as hot exhaust that is vented to atmosphere, or as gas or steam pressure that is deflated with valves. A quick summary of energy that could be recycled from documented waste streams follows.

- ***FLARE GAS:*** *US industry produces, per EPA data,[1] 88,000 megawatt-hours of low grade waste gas every hour, and then largely flares the gas to burn out remaining pollutants. This gas could be recycled to produce 22,000 megawatts of new electric generation (equivalent to 22 large nuclear plants) and no thermal energy, or could be recycled into enough thermal energy to displace up to 3.2 trillion cubic feet of natural gas per*

[1] EPA Aerometric Data

year, enough to displace 13.7% of all natural gas burned in the US in 2002. There are large projects serving steel mills that prove the concept. Primary Energy generates 290 megawatts of electricity and several hundred thousand pounds of steam for three northern Indiana steel mills with flare gas from their blast furnaces, demonstrating what can be done.

- ***EXHAUST HEAT:*** *US industry also vents hot exhaust from many processes from blast furnaces to glass production, from petroleum refining to coke production, from foundries to chemical production and drying applications. There is no currently required measurement or reporting of energy vented as hot exhaust, but using industry experience, existing projects, and the US Department of Energy's national lab studies of industries in question, we have estimated a minimum potential of 10,000 megawatt from recycling exhaust heat.*

- ***PRESSURE DROP:*** *Virtually every large complex, whether industrial, institutional or commercial, produces steam at high pressures in central boiler plants and then distributes the steam throughout the complex at relatively high pressures in order to "pack" steam into relatively small distribution pipes. At the points of use, the steam is typically deflated with a valve. The energy to produce the pressure does useful work by moving steam to point of use, but remaining pressure is then typically wasted. But steam pressure drop can drive a steam turbine and produce electricity. Natural gas pipelines expend energy to compress gas to pack the pipe and move the gas to market. At points of use, just as in the case of steam, valves are typically used to deflate the remaining pressure, wasting the energy content. Two technologies, gas expanders and reciprocating engine, convert the pressure drop to shaft power to drive electric generators. We have conservatively estimated a US wide potential of 10,000 megawatts of fuel-free, pollution-free recycled energy from steam and gas pressure drop.*

The benefits of recycled energy are clear. There is a potential to generate between 9% and 13% of the current fossil fueled electrical power by simply recycling waste energy streams. In addition, because the waste energy streams are produced on-site, the recycled electricity would be consumed locally, minimizing line losses and avoiding transmission and distribution system upgrades.

But one must ask why so little energy is being recycled. We do find significant energy recycling in Europe and Japan, where energy prices typically exceed US energy prices. And yet, barriers have prevented the development of recycled energy projects.

Finally, inclusion of recycled energy within the scope of the RPS will provide needed revenue to our nation's industrial plants. At a time when our nation's various industries are struggling to compete with their respective competitors abroad, the mandated support for recycled energy through the RPS would improve the competitive positions of industrial facilities in world markets.

The clear benefit of recycled energy is that it is fuel-free and pollution-free, and displaces fossil generation, pollutants, and greenhouse gases. In this manner, recycled energy will reduce emissions of NOx, SOx, particulate matter, mercury and hazardous air products and will reduce greenhouse gases.

Decentralized generation needs no new transmission or distribution as it is produced on-site. And while 9% of centrally generated power is lost in transmission, decentralized generation has neither transformer nor line losses because it is also consumed on-site. Even power generated on-site in excess of use will flow to the nearest user, regardless of power sales contract, thereby freeing the T&D system and allowing the existing wires to serve other loads. The overtaxed transmission system will cause more power failures unless 1) more transmission lines are constructed, 2) decentralized generation is built near users, or 3) a combination of both is pursued. Clearly, U.S. policy should encourage the development of more decentralized generation.

Much energy is vented from industrial processes or is lost in the pressure drop of any gas, but little is currently recycled – converted to electricity. The three major sources of recyclable energy are 1) exhaust heat from industrial processes including electric generation, 2) industrial process fugitive tail gas that is flared without energy recovery and 3) gas and steam pressure drop that could provide nearly fuel-free electricity. We list below the identified sources of currently wasted energy. These sources could produce 240,000 to 360,000 gigawatt hours per year of recycled electricity – 9% to 13% of US fossil-fuel based generation.[1]

New electric generation also has energy recycling potential. The US DOE and EPA both have programs to double the percentage of power produced in combined heat and power installations, known as CHP plants, by 2010. By producing steam at higher pressures, these new plants can convert some exhaust energy to electricity at 80% plus efficiency. The extra electricity is essentially fuel-free and pollution-free. This source has not been counted in this analysis.

Similarly, steam systems serving multiple buildings generate steam at ten times atmospheric pressure or higher, to pack more steam in relatively small pipes, and then reduce the pressure at point of use to twice atmospheric pressure with a valve. Backpressure steam turbine generators can convert the pressure drop to fuel-free electricity.

The attached table shows the potential for recycled energy by state and the retail value of each state's recycled energy potential. The table limits results to published data and shows the annual kWh per capita of recycled energy potential for each state as well as the current renewable energy production in kWh/capita. Each state and the District of Columbia is ranked from 1 (highest kWh/capita) to 51 for both recycled energy potential and for renewable energy production. Some states with low renewable kWh/capita rankings have high rankings on recycled energy potential. For example, Texas is 44th in renewable but 5th in recycled energy potential. Louisiana is 51st on renewable energy today, but, in spite of under reporting, 23rd on recycled energy.

Recycled energy will be easy to measure, as it will largely come from discreet, non-fueled generators. In some cases, recycling will require a small amount of fossil fuel to stabilize the combustion or to add heat. If that fossil fuel were burned in a conventional electric plant, one third of the energy would be converted to electricity. Thus, an RPS definition of recycled energy should exclude an amount of electricity equal to 33% of the energy content of any incremental fossil fuel burned. The proposed amendment assumes advances in fossil efficiency and deducts 40% supplemental fuel energy content from the RPS definition.

In regulated markets, electrical generation and distribution were natural monopolies and the incumbent utilities had little incentive to capture waste energy. As a result, unintended (and sometimes-intended) barriers were enacted that block the deployment of recycled energy facilities.[4]

Unfortunately, while electricity markets are evolving, many of the barriers to recycling energy remain. Few institutions have been able to develop energy recycling in spite of numerous attempts because of the following regulatory barriers and common practices:

The RPS in the Senate's recently passed energy bill contains a requirement that all retail electric suppliers purchase credits from eligible renewable facilities, rising to 10% of the supplier's retail sales by 2020. In addition, the RPS language in the Senate bill imposes a credit cap of 3 cents per kilowatt-hour. The rising mandate for credits from renewable sources should force the price of the credit up to the cap as more expensive RPS sources are brought on line. Recycled energy, on the other hand, would be able to overcome its barriers to deployment with credits smaller than the 3 cent cap. In fact, recycled energy facilities could overcome barriers to deployment with a much smaller credit, making recycled energy a very cost-effective RPS source of power that will lower the overall cost of the program.

The RPS definition currently in the Senate energy bill would primarily benefit certain regions in the country, with ratepayers in other regions of the country paying for that support. If existing renewable generation is taken as an indicator of RPS induced renewables, then states like California, Montana, the Dakotas and Washington will be major beneficiaries, while states like Indiana, Ohio and Texas stand to lose revenue to other states. But these low renewable states have high-recycled energy potential and could satisfy the expanded RPS requirement. Accordingly, adding recycled energy to the RPS definition of eligible sources would extend the benefits of the RPS to many more States.

Public education would be an important value of RPS-mandated support for energy recycling. Worldwide production of heat and power is less than optimal. Barriers prevent the optimal deployment of decentralized generation. A national RPS mandate to support renewable and recycled energy will result in the deployment of clean, localized energy generation in every community, at most factories and on many rooftops. The public will learn that decentralized electric power will reduce the need for central station generation facilities or upgraded transmission wires. The RPS mandate will force the industry to recognize the locational value of decentralized energy. It will also give regulators experience with decentralized technologies, providing them with the necessary information to eliminate the barriers to the deployment of such technologies. The following amendment would add recycled energy to the RPS definition:

> ***Amend Section 606 of the Senate energy bill by adding ", recycled energy" after "generation offset," in subsection (l)(3) and subsection (l)(10) and by adding the following after subsection (l)(13):***
>
> ***Overcoming the barriers to recycling energy could be achieved through the inclusion of recycling energy within the scope of the Renewable Portfolio Standard (RPS). Senate Energy Bill S. 517 contains an RPS provision that requires US electric providers to purchase credits from a rising percentage of RPS-defined sources. The purposes of the RPS are to reduce our country's dependence on fossil fuel and at the same time reduce the emissions of harmful pollutants and greenhouse gases. Adding recycled energy to the list of RPS-defined sources would accomplish both purposes. Recycled energy production, like renewable power, displaces fossil generation. In addition, recycled energy, by displacing fuel, will significantly reduce emissions of sulfur dioxide, nitrous oxide and carbon dioxide associated with electricity production.***

The Value of Recycled Energy

Recycled energy, like other decentralized energy sources, also provides an alternative to expensive, and often controversial, transmission expansion. The need for such an alternative has become especially clear over the past few years. A spate of recent power failures and electricity generation shortages has pointed to the need for both increased generation and transmission upgrades and expansions. While there is no question that some upgrades may be required, it is a mistake to conclude that the only solution to the existing problems is to build central station generation facilities and transmission upgrades. Instead, decentralized generation offers an alternative, and a relatively less costly one at that.

Recycled Energy Potential

Potential recycled energy, using only available data, could displace 9% of current US fossil generation. However, such an estimate could reach 13% of fossil-fueled electrical generation by tapping other waste sources not considered or missing data.

Exhaust Heat: Exhaust from many industrial processes – steel mills, glass producers, refineries and chemical processes – is vented at 800 to 3,000 degree F. Exhaust from the reciprocating engines and combustion turbines driving gas pipeline compressors is vented at roughly 1,000 degree F. Condensing steam turbine generators can convert 25% of the energy in each of these sources to electricity <u>without burning any added fossil fuel or emitting any added pollution</u>. For installations with low-grade thermal energy needs nearby, the spent steam from backpressure turbine generators can displace boiler fuel and increase recycling to 90% of the exhaust energy.

Industrial Tail Gas: Many industrial processes emit fugitive gas that is flared to reduce hazardous air products. The US EPA aerometric survey identifies 2800 separate point sources of tail gas, with several states not fully reporting.[2] These fugitive gases come from carbon black plants, refineries, chemical factories, automobile and appliance painting operations and ethanol plants. Converting the existing fugitive gas flares to the burners needed for heat recovery will improve combustion and lower stack pollution. Recycled electricity displaces central generation, further lowering pollution. Based on this logic, EPA's MACT guidance for carbon black flare gas states that equipment for recovering heat as described above is a pollution control device.
Recycled tail gas could support 148,000 GWh/year of new fuel-free electrical generation.

Gas Pressure Drop: Many processes compress gas or steam to pack more gas or energy into a pipe. Transcontinental natural gas pipelines compress gas to 40 to 110 times atmospheric pressure. Every 50 miles or so, another compressor station boosts the gas pressure for travel to the next station. When the pressurized gas reaches distribution points, pressure is reduced with valves to as low as two times atmospheric pressure. This wastes the energy recovery potential of the pressure drop. Expansion turbine generator sets can lower gas pressure and produce fuel-free electricity.

We estimate wasted gas or steam pressure drop could support 78,000 GWh/year of fuel-free generation.

Total Potential for Recycled Energy: Total recycled energy from published data would support 240,000 gigawatt hours per year of fuel-free electrical generation, equivalent in annual output to one third of US nuclear generation in 1999.[3]

State by State Data

Why Is So Little Energy Recycled Today?

- *Regulated local utilities have little incentive to build recycled energy projects. Fuel savings would simply lower user electricity prices while utility management would have to deal with many small projects.*
- *Producers of tail gas, exhaust heat and pressure drop are not in the energy business and tend to "stick to their knitting," or in current management speak, focus resources on core competencies.*
- *Independent power developers, whose core competency is energy, face high capital costs, high standby and interconnection charges for small recycled energy projects, and then receive discounted prices for the power because the below 50 megawatt blocks do not fit the current power market.*
- *Regulated local utilities, to avoid losing sales and profits, use many techniques to block all decentralized generation.*

Although the societal benefits of recycled energy are clear, few recycled energy projects have been developed. The barriers to recycling energy will continue to impede successful deployment unless certain actions are taken.

Why Recycled Energy Should be Included Within the Scope of the Renewable Portfolio Standard

As explained above, a number of barriers have served to limit the deployment of recycled energy facilities. Nevertheless, the value of such facilities from both an economic and environmental standpoint is clear. A national RPS standard mandating support for recycled energy would serve as an elegant wedge to force modernization of the rules that currently act as barriers to such efficiency. And the inclusion of recycled energy within the scope of the RPS would result in a program that is more cost-effective, more broadly shares the benefits across states, and will be more beneficial for the nation's economic well-being.

Broadening the Scope of the RPS to Include Recycled Energy Should Lower the Overall Cost of the RPS

Including Recycled Energy within the Scope of the RPS Would Result in an RPS that is More National in Scope

Including recycled energy within the Scope of the RPS would Benefit US Industry

Including recycled energy within the scope of the RPS will provide US industrial plants with payment for their presently wasted energy. In addition, recycled electricity generation with exhaust heat and tail gas will produce spent steam that can offset fossil fuel for industrial and institutional thermal needs, further reducing heating costs. Such value from recycled energy would lower costs of production, thereby improving the competitive position of US industries in world markets.

In addition to the benefits to the on-site facility, mandating support for recycled energy will push several technologies up the learning curve, improving their value position. American exports of clean energy products will thus increase.

Including Recycled Energy within the Scope of the RPS Would Educate the Industry on the Benefits of Decentralized Generation

Proposed Inclusion of Recycled Energy in RPS Definition:

> *"(14) **RECYCLED ENERGY**. The term 'recycled energy' means (1) exhaust heat resulting from any industrial process; (2) industrial tail gas that would otherwise be flared, incinerated, or vented; or (3) energy extracted from a pressure drop in any gas, excluding any pressure drop from a condenser that subsequently vents the resulting heat. If the process used to recycle energy incorporates supplemental use of a fossil fuel, the amount of the recycled energy that qualifies as a renewable eligible resource shall be reduced by 40% of the net heating value of the incremental fossil fuel used in the process."*

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[1] Internal analysis of Private Power based on US EPA data cited below, individual industry data and pipeline compressor databases.

[2] US EPA Envirofacts database, July 2001. http://www.epa.gov/enrivo/index_java.html

[3] Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and Form EIA-900, "Monthly Nonutility Power Plant Report, and Form EIA-860B, "Annual Electric Generator Report – Nonutility".

[4] See chapter 8, Barriers to Efficiency, in "Turning Off The Heat," by Thomas R. Casten, Prometheus Press, 1998.

Economic Growth and the Central Generation Paradigm

*By Thomas R. Casten and Brennan Downes**

Editor's Note: In his President's Message in the Third Quarter *IAEE Newsletter*, Tony Owen said, regarding the 24th Annual North American Conference of the USAEE/IAEE, "Although a consistently high standard of plenary session presentations was a feature of the conference, it would be remiss of me not to mention the invited lunch address by Tom Casten, CEO of Primary Energy LLC. Entitled *Economic Growth and the Central Generation Paradigm*, Tom held the audience in rapture with his brilliantly articulated message… I encourage those who were not fortunate enough to be present to take a serious look at his message." Read on.

Executive Summary

We question the worldview that central generation of electric power is optimal. This paper analyzes past power generation and delivery options and finds the power industry consistently made sub-optimal choices over the past three decades. We modeled eight scenarios for meeting expected US load growth through 2020 and found that future reliance on decentralized generation that recycles energy would save roughly 40% on incremental capital costs, power costs and emissions versus use of new central generation. Decentralized generation also improves power quality and reduces the grid's vulnerability to extreme weather and terrorism.

We then extrapolated US findings to the International Energy Agency (IEA) Reference Case for energy through 2030. Satisfying expected load growth with conventional central generation will cost \$4.2 trillion for generation and \$6.6 trillion for new transmission and distribution wires (T&D), a total of \$10.8 trillion. If the percentage savings found in the US study hold, the world can save \$5.0 trillion or 46% in capital costs by building all new generation near users. By avoiding line losses, recycling industrial process heat to produce power and recycling waste heat from fuel fired power generation, the DG approach avoids use of 122 billion barrels of oil equivalent of fossil fuel, saves \$2.8 trillion in fuel costs and cuts carbon dioxide emissions associated with incremental power generation by 50%.

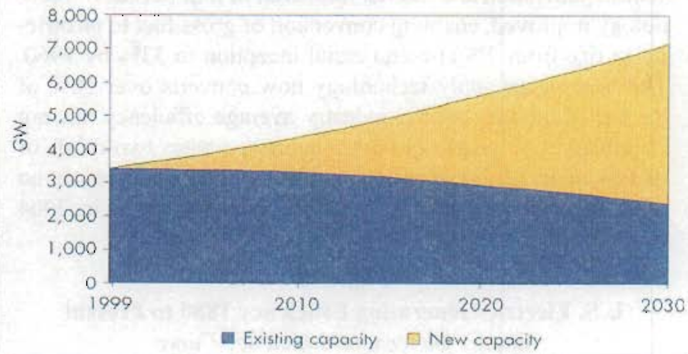
We suggest two policy changes to guide the power industry towards optimal choices. The global fix, requiring enormous political will, removes all existing barriers to efficiency stemming from monopoly protection of the power industry. The second approach simply sends an economic signal to increase fossil efficiency.

Conventional Power Generation

We believe the conventional "central generation paradigm" is obsolete, based on last century's technology, but power industry regulations largely derive from the unquestioned belief that central generation is optimal. Meeting the world's growing appetite for electric power with conventional central generation will severely tax capital markets, fossil fuel markets and the global environment. The International Energy Agency's (IEA) 2002 World Energy Outlook Reference Case – based on present policies – presents a frightening view of the next 30 years[1]. The Reference Case says world energy demand will grow by two-thirds with fossil fuels meeting 90% of the increase. World electrical demand doubles, requiring construction of nearly 5000 Gigawatts of new generating capacity, equivalent to adding six times current United States electric generating capacity. The generation alone will cost \$4.2 trillion, plus T&D costs of \$6.6 trillion (2004 US dollars). Global carbon dioxide emissions increase by 70%. See Figure 1.

Figure 1

World Installed Electricity Generation Capacity



The Reference Case assumes that the energy policies of each government in 2002 continue without change, a modest evolution of technology and continued reliance on central generation of electric power, which is consistent with most existing policies and regulations. The IEA projections assume that central generation is the optimal approach, given today's technology.

The IEA report is silent on the need for or capital cost of new T&D, even though existing T&D is far from adequate. There have been 105 reported grid failures in the US since January of 2000, and eleven of those outages affected more that one half million people.[2] US consumers paid \$272 billion for electricity in 2003[3], plus power outage costs, estimated between \$80 billion and \$123 billion per year. Outages thus add 29% to 45% to the cost of US power.[4] The T&D situation is worse in developing countries, where 1.6 billion people lack any access to electric power and many others are limited to a few hours of service per day. Satisfying expected load growth with central generation will clearly require at least comparable construction of T&D capacity.

We question the "central generation paradigm". Close examination of past power industry options and choices suggests that load growth can be met with just over half the fossil fuel

*Thomas R. Casten is Chair and CEO and Brennan Downes, Project Engineer of Primary Energy. This is an edited version of Casten's remarks at the 24th North American Conference of the USAEE/IAEE, held in Washington, DC July 8 to 10, 2004.

[1] See footnotes at end of text.

and pollution associated with conventional central generation We had better get this world energy expansion right.

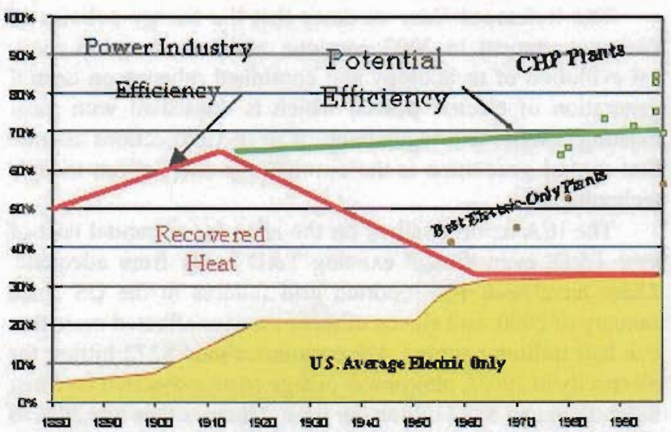
We make these major points:

- The power industry has not deployed optimal technology over the past 30 years
- The universally accepted "Central Generation Paradigm" prevents optimal energy decisions.
- Decentralized generation (DG), using the same technologies used by remote central generation, significantly improves every key outcome from power generation, and,
- Meeting global load growth with decentralized energy can save \$5.0 trillion of capital, lower the cost of incremental power by 35-40% and reduce CO_2 emissions by 50% versus the IEA central generation dominated reference case.

A Brief History of Electric Generation– Living Moore's Law in Reverse

Figure 2 shows that US net electric efficiency peaked in about 1910, when nearly all generation was located near users and recycled waste heat. That efficiency dropped to 33% over the next 50 years as the power industry moved to electric-only central generation and has not improved in four decades. Technology improved, enabling conversion of gross fuel to electricity to rise from 7% at commercial inception to 33% by 1960. The best electric-only technology now converts over 50% of the fuel to power, but the industry average efficiency has not improved in 43 years. No other industry wastes two-thirds of its raw material; no other industry has stagnant efficiency; no other industry gets less productivity per unit output in 2004 than they did in 1904.

Figure 2
U.S. Electric Generating Efficiency 1880 to Present
Energy Generation Efficiency Curve



Early generating technology converted 7% to 20% of the fuel to electricity, making electric-only production quite expensive. To reduce fuel costs, energy entrepreneurs, including Thomas Edison, built generating plants near thermal users and recycled waste heat, increasing net electric efficiency to as much as 75%. A second wave of technical progress post World War II drove electric-only efficiencies to 33%, after distribution losses and increased individual plant size to between 500 and 1000 megawatts. Central or remote generation of electricity only, while still wasting two-thirds of the input energy, became the standard. Buttressed by monopoly protection, utilities fought competing on-site generation and, by 1970, replaced all but 3-4% of local generation, ending waste heat recycling. Government regulations, developed over the first 90 years of commercial electricity, institutionalized central generation.

The third wave of technical progress should have reversed the central generation trend. Modern power plants emit only 1-2% as much NOx as 1970 plants, come in all sizes, burn all fuels and are good neighbors. Many technical advances make local or distributed generation technically and economically feasible and enable society to return to energy recycling, displacing boiler fuel and doubling net electric efficiency. However, protected from competition and rewarded by obsolete rules, the power industry continues to build remote plants and ignores opportunities to recycle energy.

The green squares in Figure 2 represent the alternative to central or remote generation. These are actual plants employing central plant generation technologies that are located near users. These combined heat and power plants (CHP) achieve 65% to 97% net electrical efficiency by recycling normally wasted heat and by avoiding transmission and distribution losses. US Energy Information Agency (EIA) records show 931 distributed generation plants with 72,800 megawatts of capacity, about 8.1% of US generation. These plants demonstrate the technical and economic feasibility of doubling US electric efficiency.

Nevertheless, the US and world power industry ignores and indeed actively fights against distributed generation. Conventional central generation plants dump two-thirds of their energy into lakes, rivers and cooling towers, while factories and commercial facilities burn more fuel to produce the heat just thrown away. We do not believe the power industry has made optimal choices, and set out to test this thesis with data.

The Worldwide Heat & Power System Is Deeply Suboptimal

To determine whether the power industry made optimal choices, we analyzed EIA data on all 5,242 reported generation plants, separating plants built by firms with monopoly-protected territories and plants built by independent power producers. We calculated what price per KWh would be required for each of four central generation technologies, built in each year, to provide a fair return on capital.[5]

We also analyzed distributed generation or DG technology choices. Several clarifications are necessary:

- Distributed generation is any electric generating plant located next to users.
- DG is not a new concept. Edison built his first commercial electric plant near Wall Street in lower Manhattan, and recycled energy to heat surrounding buildings.
- DG plants employ all of the technologies that are used in central generation
- DG plant capacities range from a few kilowatts to several hundred megawatts, depending on the users' needs. We have installed 40-kilowatt backpressure steam turbines in

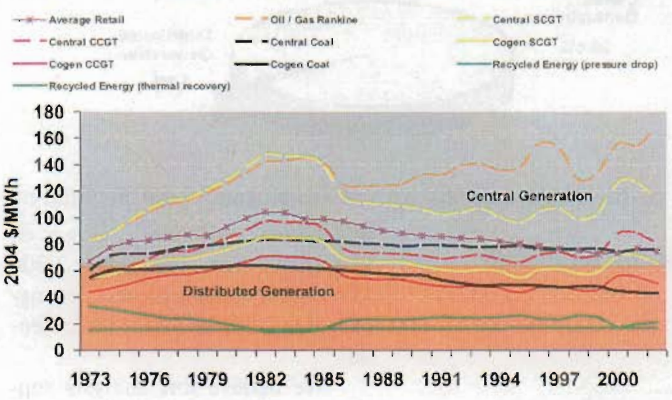
office buildings that recycle steam pressure drop, and managed a 200-megawatt coal fired CHP plant serving Kodak's world headquarters in Rochester, NY.

- DG can use renewable energy, but not every renewable energy plant is DG. Solar photovoltaic panels on individual buildings or local windmills are distributed generation, while large hydro and wind farms are central generation requiring T&D.
- DG uses all fuels, including nuclear. Modern naval vessels generate power with nuclear reactors and then recycle waste heat to displace boiler fuel.

Power generated near users avoids the need for T&D. We have assumed each KW of new DG will require net T&D investment equal to only 10% of a KW, for backup services.[1] Third, we assume DG plants require a 50% higher average cost of capital (12% versus 8%) due to risks and transaction costs. Industrial companies that install DG see power generation as a non-core activity and demand 35% to 50% rates of return, but this analysis focuses only on power companies' cost of capital.

Figure 3 depicts results. The burgundy line with asterisks shows the average price of power to all US consumers in each year. The dashed lines show four power generation technologies built as central stations, unable to recycle waste heat. The solid lines show required prices per megawatt-hour from deploying the same technologies near thermal users to recycle waste heat. The solid green lines depict prices/MWh needed for power generated with recycled industrial process heat or flare gas, and power extracted from gas or steam pressure drop.

Figure 3
Long Run Marginal Cost of Central Electricity Generation



Thermal plants generate steam by burning fossil fuel in boilers. The steam then drives condensing steam turbines. Thermal generation technology matured in the mid-fifties, achieving maximum electric-only efficiency of 38% to 40%, before line losses. Over the entire period, new central oil and gas thermal plants (dashed orange line) required prices well above average retail. Gas turbines use a different cycle; the technology improved dramatically over the period. Simple cycle gas turbine plants (dashed yellow line) required similar prices to gas-fired thermal plants until 1985-90, when improving turbine efficiency reduced fuel and lowered required prices. New coal plants, (dashed black line) required lower prices than average retail each year until 1998. However, environmental rules blocked coal plants in many states.

Combined cycle gas turbine plants (CCGT's) are the same gas turbines as above, but then make steam with the turbine exhaust to drive a second power generation cycle -- a condensing steam turbine. The first commercial applications of CCGT's were in 1974. These plants cost less to build than an oil and gas thermal plant and initially achieved 40% efficiency, which rose to 55% by 1995.

Distributed Generation Recycles Energy to Reduce Costs

The solid lines show prices required for distributed generation or DG; building the same technologies near thermal users and recycling normally wasted heat. The solid lines demonstrate the economic value of recycling energy. Burning coal in combined heat and power plants, (solid black line) saves $11.00 to $27/MWh versus burning coal in new central plants. Simple cycle gas turbine plants built near users (solid yellow line) save $25 to $60 per MWh versus the same technology producing only electricity. Building combined cycle gas turbine plants near users and recycling waste heat saves even more money, reducing required costs by $25/Mwh versus the same technology built remote from users.

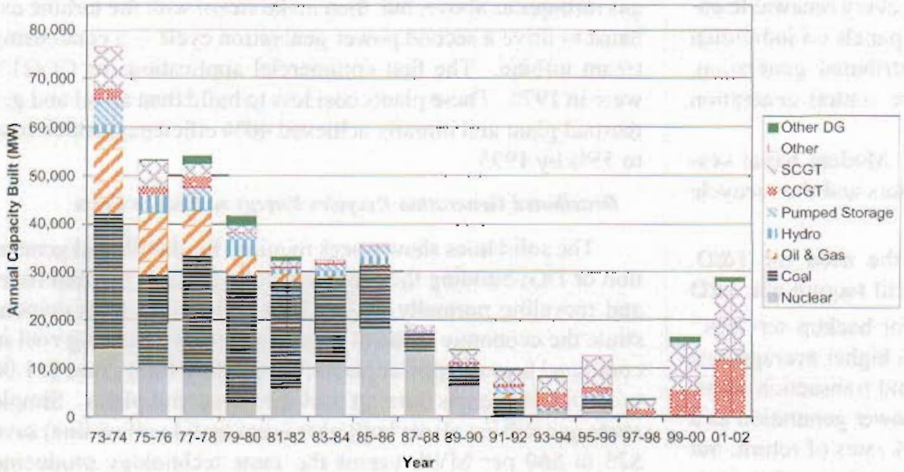
The lowest cost power avoids incremental fossil fuel by recycling waste energy from process industries. Process industries use fossil fuel and/or electricity to transform raw materials, and then discard energy in three forms including hot exhaust gas, flare gas and pressure drop. Local "bottoming cycle" generation can recycle this waste into heat and/or power. The green line that varies over time shows the retail price per megawatt-hour needed for power recycled from waste heat or flare gas, after credit for displacing boiler fuel with the recovered heat. These energy-recycling plants can earn fair returns on capital at 25 to 50% of average retail prices.

Steam and natural gas distribution systems use high pressures for distribution and then reduce pressure at points of use. Backpressure turbines and gas expanders can recycle this pressure drop to drive generators without any incremental fuel or pollution. The flat green line shows that plants recycling pressure drop required $18 per MWh, 72% to 83% below average retail prices.

Did the Power Industry Make Optimal Choices for New Capacity?

To determine whether the electric power industry made optimal choices, we analyzed all power plants built since 1973. Figure 4 depicts the new generation built every two years by monopolies, which we defined as any utility with a protected distribution territory. Monopoly utilities included investor owned utilities, cooperatives, municipal utilities, state and federally owned utilities. They collectively built 435,000 megawatts of new generation, but ignored energy recycling, even though it was always the cheapest option. They continued to build oil and gas thermal plants (orange bar) long after CCGT plants were a cheaper central option. Monopoly utilities were slow to make optimal choices among central plant technologies and completely ignored the more cost effective distributed use

Figure 4
Annual U.S. Utility Additions of Electric Generating Capacity by Technology
1973-2002

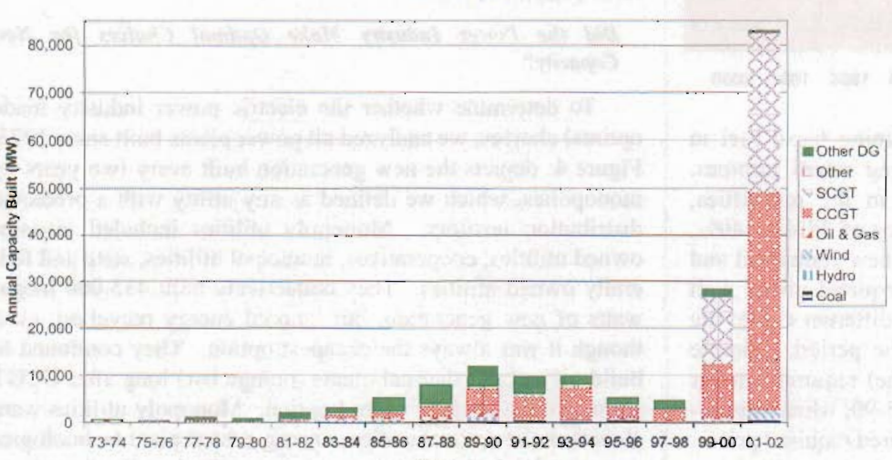


of the same technologies.

Figure 5 shows the 175,000 MW of new generation built by independent power companies since 1973. Virtually all new IPP plants were DG and/or combined cycle plants until the last four years. The price spikes of 1998 -2000 apparently induced IPP companies to install simple cycle gas turbines for peaking. Prior to 1978 passage of the Public Utility Policy Regulatory Policy Act or PURPA, it was illegal to build generation as a third party. Between 1978 and the law change in 1992, IPP's were allowed to build qualifying facilities – those that recycled at least 10% of the fuel's energy for heat use, or utilized certain waste fuels. Post 1992, IPP's could legally build remote electric-only generation plants.

For another view of industry choices, we divided plants built since 1973 into those recycling and not recycling energy. Generating plants that recycle energy must be near thermal users or near sources of industrial waste energy. Figure 6 shows that of the 435,000 megawatts of new generation built by monopolies over the 30-year period, only 1.2% or 5,000 MW

Figure 5
Total U.S. IPP Additions of Electricity Generation Capacity by Technology
1973-2002

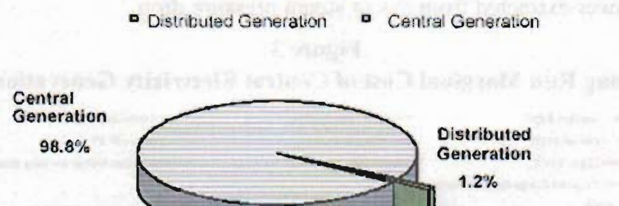


recycled energy. We doubt that these choices would be profitable in a competitive marketplace.

Independent power producers built 34% of their total capacity as DG plants, at or near users. The IPP companies took what government allowed. Federal law banned independent generation prior to 1978, then allowed only "qualifying facilities" that recycled at least 10% of the fuel energy as heat. Post 1992, independent wholesale generation was legalized and the IPP industry shifted focus to larger electric-only plants that are remote – central generation. Figure 7 depicts the mix of central and distributed power built by IPP's since 1978.

Finally, we estimated the potential generation from the least cost options – those plants that recycle industrial process waste energy. EPA aerometric data and other industry analyses suggest that US industrial waste energy would power 40,000

Figure 6
Total Generation Capacity Built by U.S. Electric Utilities
1973-2002



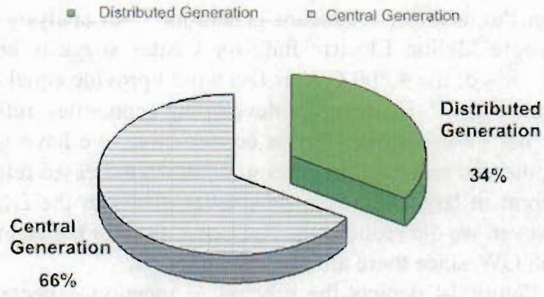
to 100,000 megawatts with no incremental fossil fuel and no incremental pollution.[7] However, EIA plant data show only 2,200 MW of recycled industrial energy capacity, 2.2% to 5% of the potential.[8]

We believe this analysis supports our thesis that the power industry has made suboptimal choices. This data shows that utilities eschewed least cost generating technologies, effectively driving up costs to all customers.

Meeting Expected US Load Growth with Local Generation

Our colleagues built a model to determine the optimal way to satisfy projected load growth for

Figure 7
Total Generation Caacity Built by U.S. Electric IPPs 1973-2002



any nation over the next two decades.[9] The model incorporates relevant factors for central and distributed electric generation technologies, including projected improvements in cost, efficiency and availability of each technology. The model assumes new central generation will require 100% new T&D and new DG will require new T&D equal to 10% of added generating capacity. The model assumes 9% line losses for central power, equal to US losses for 2002, and 2% net line losses for DG power.

Figure 8
DG as a Percentage of Total US Generation

Impact of Generating 2020 Load Growth with Central or Decentralized Generation

	100% CG	100% DG	*Savings*	% Change
Total Capital Cost (Capacity + T&D) Billions of Dollars	$831	$504	$326	39%
2020 Incremental Power Cost Billions of Dollars	$145	$92	$53	36%
2020 Incremental Power Cost Cents/KWh	8.61	5.47	3.14	36%
Emissions from New Load Thousand Metric Tonnes				
NO_x	288	122	166	58%
SO_2	333	19	314	94%
PM10	22	12	9	43%
Million Metric Tonnes CO_2	776	394	381	49%

Although the future surely includes some mix of central and decentralized generation, the model calculates the extreme cases of meeting all load growth with central generation, or meeting all growth with decentralized generation. Local generation that recycles energy improves every important outcome versus full reliance on central generation. Figure 8 compares the extreme cases. Full reliance on DG would avoid $326 billion in capital by 2020, reduce incremental power costs by $53 billion, NOx by 58%, and SO_2 by 94%. Full DG lowers carbon dioxide emissions by 49% versus total reliance on new central generation. (2002 dollars)

The referenced report provides detail of eight scenarios utilizing various mixes of DG and central power. The next four figures spread the scenarios across the horizontal axis and use stacked bars to show the breakdown of costs from the central plants and from the decentralized plants in the scenario.

Figure 9
Capital Cost to Supply 2020 Electric Load Growth

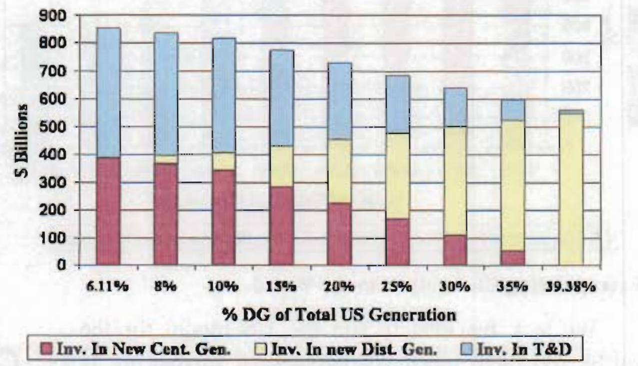


Figure 10
Added Annual Fossil Fuel Use for Incremental 2020 U.S. Load

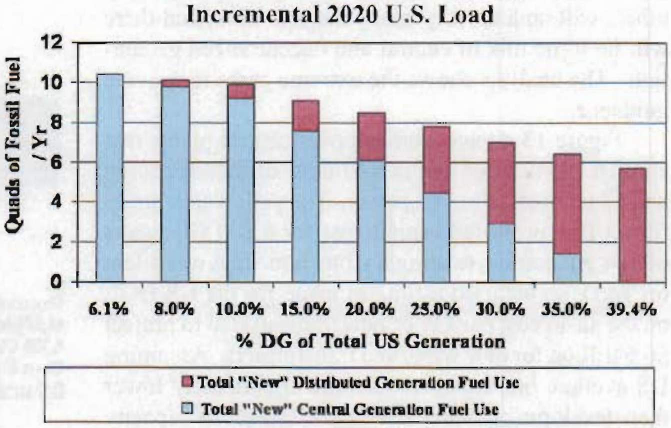


Figure 11
Emissions from Generating Incremental 2020 U.S. Load

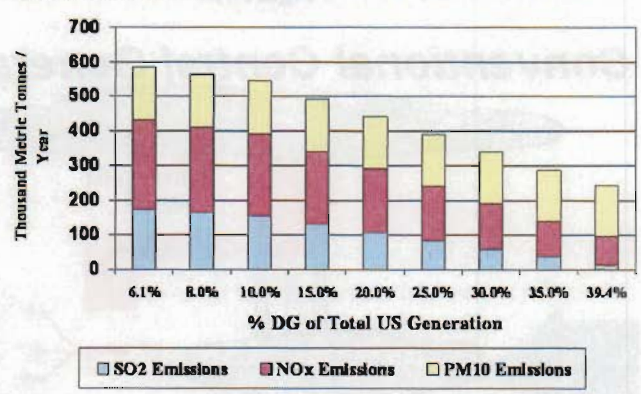
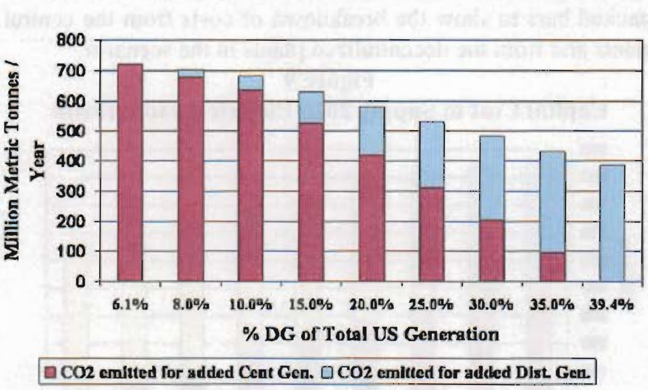


Figure 12
Added Annual CO_2 Emissions for Incremental 2020 U.S. Load



Extrapolating US Analysis to the World

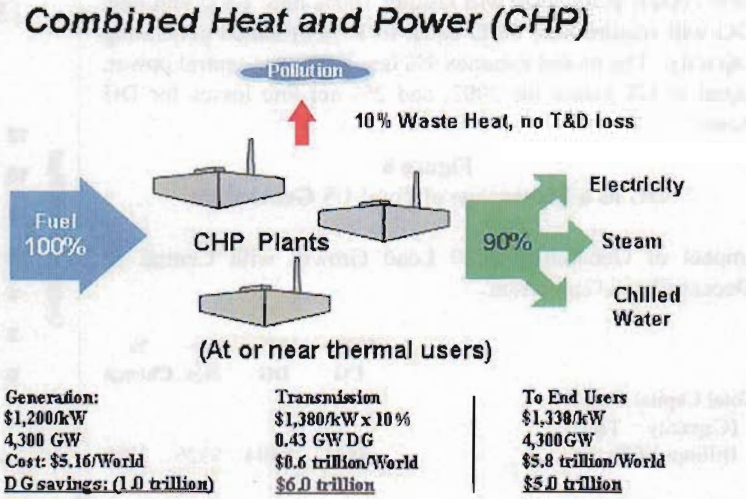
We lack the data to run the US model for the world, but have taken the percentage savings to be directionally correct and applied them to the IEA load growth projections through 2030. Detailed analysis by others will undoubtedly refine the estimates, and there will be some mix of central and decentralized generation. The analysis shows the extreme cases to provide guidance.

Figure 13 depicts conventional central plants that convert 100 units of fuel into 67 units of wasted energy and 33 units of delivered power. The yellow text boxes reflect IEA projected capital cost for 4,800 Gigawatts of new generation, totaling $4.2 trillion. IEA was silent on T&D, so we used estimates made for the US DOE on the all-in cost per kW of new transmission to project $6.6 trillion for new wires and transformers. Assuming US average line losses, which are significantly lower than developing country line losses, 9% of the capacity will be lost, leaving 4,368 GW delivered to users. To achieve the IEA Reference Case with central generation, the world must invest $10.8 trillion capital, roughly $2,500 per kW of delivered capacity.

Meeting IEA Reference Case load growth with DG will lower the need for redundant generation. An analysis by the Carnegie Mellon Electric Industry Center suggests building only 78% of the 4,800 GW as DG would provide equal or better reliability.[10] However, in developing economies, reliability may not be the driver. To be conservative, we have ignored the potential reduction in generation due to increased reliability inherent in larger numbers of smaller plants in the DG case. However, we did reduce required generation for the DG case to 4,368 GW, since there are no net line losses.

Figure 14 depicts the process of meeting expected load growth with distributed generation. We estimated average capital costs for distributed generation of $1,200 per kW, $310

Figure 14

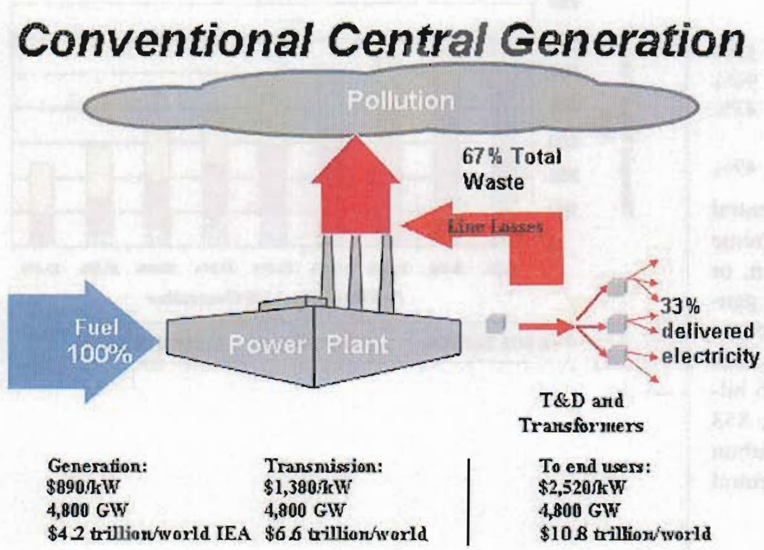


greater than a kW of central generation. Even with 9% less DG capacity, the capital costs for generation increase to $5.2 trillion, $1.0 trillion more than building central plants. Looking only at generation costs, DG is not competitive. However, the full DG case requires only 430 GW of new T&D, costing $0.6 trillion, a $6 trillion savings on T&D. End users receive 4638 GW in both cases, but society invests $5.0 trillion less for the DG case.

Everyone knows that, "You get what you pay for". What does the world give up by selecting a $5.0 trillion cheaper approach to meet projected electric growth? We extrapolated US analysis to the IEA Reference Case and found the world would give up the following by adopting the cheaper DG case:

- Consume 122 billion fewer barrels of oil equivalent (½ Saudi oil reserves)
- Lost fossil fuel sales of $2.8 trillion
- Lost medical revenues from air pollution related illnesses

Figure 13



- Potentially lost savings if governments opt to supply electric services to entire population instead of leaving 1.4 billion people without electric access
- Less global warming due to 50% less CO_2 emissions.

Recommended Actions

If this analysis survives critical review, then what policy reforms will steer the power industry toward optimal decisions, given available technology? This subject will engender heated debate. We offer two potential approaches, hoping to start the policy debate.

Comprehensive Reform – ERRATA

Governments guide the electric industry with many rules, mandates and limitations that collectively cause excessive costs and fuel usage. Small regulatory changes may nudge the power industry to slight course corrections, but are unlikely to break the central generation paradigm and optimize generation.

Immediately eliminating all current barriers to efficiency would cause the electric power industry to make optimal decisions. Each government could examine every rule that impacts power generation and delivery and ask whether the social purpose behind that rule still exists. Then each state our country could enact comprehensive legislation that we term the Energy Regulatory Reform and Tax Act or ERRATA, to correct all of the mistakes in current law. ERRATA would deregulate all electric generation and sales, modernize environmental regulations to induce efficiency and change taxation to reward efficiency.[11] Sadly, ERRATA probably will not pass except in response to deepening environmental and economic pain.

Actionable Reform, National Fossil Fuel Efficiency Standards

A second possible approach simply rewards all fossil efficient power and penalizes fossil inefficient power. Each government could enact a Fossil Fuel Efficiency Standard covering all locally used electricity, regardless of origin. This standard does not favor fuels, technologies or actors. . Here are the essential details:

- Give all delivered megawatt-hours an equal allowance of incremental fossil fuel, regardless of age of plant, technology or ownership. Start with the national average fossil fuel per MWh for the prior year.
- Spread allowances over all generation of each owner, allowing owners to comply by increasing efficiency of existing plants, deploying new highly efficient plants or purchasing fossil allowances from others.
- Reward plants requiring little or no fossil fuel, such as solar, wind, hydro, nuclear and industrial waste energy recycling, by allowing them to sell fossil fuel credits.
- Penalize fossil inefficient plants by forcing them to purchase allowances for each MWh produced.
- Base allowances on delivered power to incorporate T&D losses from central generation.
- Credit displaced fuel to CHP plants that recycle heat.
- Force all generators to purchase adequate allowances or close their plants to insure that the total allowance trading is economically neutral.
- Reduce the fossil fuel allowances per MWh each year according to a schedule, and,
- Adjust the schedule downward each year to correct for growth in total power delivered, guaranteeing that the total fossil fuel use will drop.

A Fossil Fuel Efficiency Standard would steer the power industry toward optimal choices. This will reduce power costs and emissions, which will improve local standard of living and improve the competitive position of local industry. Other states and nations will follow suit.

Conclusion

We have attempted to frame the consequences of meeting energy load growth with conventional central generation or thinking outside the box to deploy decentralized generation that recycles waste energy. The DG case saves \$5.0 trillion of capital investment while reducing power costs by 40% and cutting greenhouse gas emissions in half. There are interesting implications for worldwide energy policy if this analysis stands up to critical review.

We encourage critical review by energy economists. Spell out concerns or suggested corrections so we can collectively improve the analysis of optimal future power generation. The needed policy changes are deep and fundamental, and require a consensus among economists about directional correctness.

Let us work together to change the way the world makes heat and power.

Footnotes

[1] International Energy Agency

[2] Energy Information Administration/Electric Power Monthly, May 2004.

[3] Energy Information Administration/Monthly Energy Review June 2004.

[4] Eto, Joseph, Lawrence Berkeley National Laboratory in speech to NARUC says outages cost the US \$80 billion per year. The EPRI Consortium for Electric Infrastructure to Support a Digital Society (CEIDS), "*The Cost of Power Disturbances to Industrial & Digital Economy Companies*," June 2001, states power outages and other power quality disturbances are costing the US economy more than \$119 annually.

[5] We assembled historical data for four central generating technologies – oil and gas fired thermal plants (Rankine cycle), coal fired thermal plants, simple cycle and combined cycle gas turbines. Data for each technology and each year includes capital costs per KW, load factor and efficiency. We assumed a 25-year life to calculate annual capital amortization and the future wholesale price per MWh that would yield an 8% weighted average return on capital. Since new central generation requires new T&D, we converted estimates of \$1260 per kW for T&D in 2000\$ and adjusted for inflation, then assumed a 35-year life for T&D to calculate required T&D charges. EIA did not keep line loss statistics prior to 1989, so we estimated prior years slightly below the current 9% losses. Summing produces the retail price needed for power from a central plant using a specific technology installed in that specific year. Finally, we converted everything to 2004 dollars.

[6] Typical DG plants employ multiple generators with expected unplanned outages of 2% to 3% each. The probability of complete loss of power is found by multiplying expected unit unplanned outages

by each other. Given the existing 10,286 generators operating in the US that are less than 20 megawatts of capacity,[8] and the expectation, with barriers removed, of many DG plants inside every distribution network, spare grid capacity equal to 10% of installed DG should be more than adequate to cover unplanned outages.

[7] "*Recycled Energy: An Untapped Resource*", Casten and Collins, 2002, see www.primaryenergy.com

[8] EIA, "*Annual Energy Review 2002*", October 2003

[9] The "Optimizing Heat and Power" model has been adopted by the World Alliance for Decentralized Energy (WADE) and is being used by the EU, Thailand, Nigeria, Canada and others to ask the best way to satisfy expected load growth. For model description contact Michael Brown, Director, Email: info@localpower.org.

[10] Hisham Zerriffi [hisham@andrew.cmu.edu], personal communication. See "*Distributed resources and micro-grids*" by M. Granger Morgan, Department of Engineering and Public Policy, Carnegie Mellon University, Sept. 25, 2003 for detailed analysis of how DG provides reliability with less spare capacity.

[11] See Casten, Thomas R. "*Turning Off The Heat*" 1998, Prometheus Press, chapter 10 for a more complete description of ERRATA.

United States Association for Energy Economics

USAEE

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Energy Consultant

Dermot Gately
New York University

Michael C. Lynch
Strategic Energy & Econ. Research

The above award recipients received their awards and recognition at the 24th Annual North American Conference of the USAEE/IAEE, July 8-10, 2004 in Washington, DC.

Critical Thinking About Energy

The Case for Decentralized Generation of Electricity

Highly centralized generation of electrical power is a paradigm that has outlived its usefulness. Decentralized generation could save \$5 trillion in capital investment, reduce power costs by 40 percent, reduce vulnerabilities, and cut greenhouse gas emissions in half.

THOMAS R. CASTEN and BRENNAN DOWNES

Electricity was originally generated at remote hydroelectric dams or by burning coal in the city centers, delivering electricity to nearby buildings and recycling the waste heat to make steam to heat the same buildings. Rural houses had no access to power. Over time, coal plants grew in size, facing pressure to locate far from population because of their pollution. Transmission wires carried the electricity many miles to users with a 10 to 15 percent loss, a difficult but tolerable situation. Because it is not practical to transmit waste heat over long distances, the heat was vented. There was no good technology available for clean, local generation, so the wasted heat was a tradeoff for cleaner air in the cities. Eventually a huge grid was developed and the power industry built all-new generation in remote areas, far from users. All plants were specially designed and built on site, creating economies of scale. It cost less per unit of generation to build large plants than to build smaller plants. These conditions prevailed from 1910 through 1960, and everyone in the power industry and government came to assume that remote, central generation was optimal, that it would deliver power at the lowest cost versus other alternatives.

However, technology has improved and natural gas distribution now blankets the country. By 1970, mass-produced engines and turbines cost less per unit of capacity than large plants, and the emissions have been steadily reduced. These smaller engines and gas turbines are good neighbors, and can be located next to users in the middle of population centers. Furthermore, the previously wasted heat can be recycled from these decentralized generation plants to displace boiler fuel and essentially cut the fuel for electric generation in half, compared to remote or central generation of the same power.

But the industry had ossified. Electric monopolies were allowed to charge rates to give a fair return on capital employed. To prevent excessive or monopoly profits, the utilities have long been required to pass 100 percent of any gain in efficiency to the users. This leaves utilities with no financial incentive to adopt new technologies and build decentralized generation that recycles heat. In fact, such local generation erodes the rationale for continued monopoly protection—if one can make cheap power at every factory or high rise apartment house, why should society limit competition?

Congress tried to open competition a little bit in 1978, and some independent power companies began to develop on-site generation wherever they could find ways around the monopoly regulation. One author (Casten) was one of those early pioneers, working to develop more efficient decentralized generation since 1975. This article summarizes extensive research into the economically optimal way to build new power generation in each of the past 30 years, given then available technology, capital costs, and fuel prices, and concludes that the continuing near-universal acceptance of the "central generation paradigm" is wrong. The result is a skeptical look at the world's largest industry—the electric power industry—with surprising conclusions.

Power industry regulations largely derive from the unquestioned belief that central generation is optimal. However we believe the conventional "central generation paradigm" is based on last century's technology. Meeting the world's growing appetite for electric power with conventional central generation will severely tax capital markets, fossil fuel markets, and the global environment. The International Energy Agency's (IEA) 2002 World Energy Outlook Reference Case—based on present policies—presents a frightening view of the next thirty years.[1] The Reference Case says world energy demand will grow by two-thirds, with fossil fuels meeting 90 percent of the increase. World electrical demand doubles, requiring construction of nearly 5,000 gigawatts of new generating capacity, equivalent to adding six times current United States electric generating capacity. The generation alone will cost \$4.2 trillion, plus transmission and distribution (T&D) costs of \$6.6 trillion (2004 U.S. dollars). Under this projection, global carbon dioxide emissions increase by 70 percent; see figure 1.

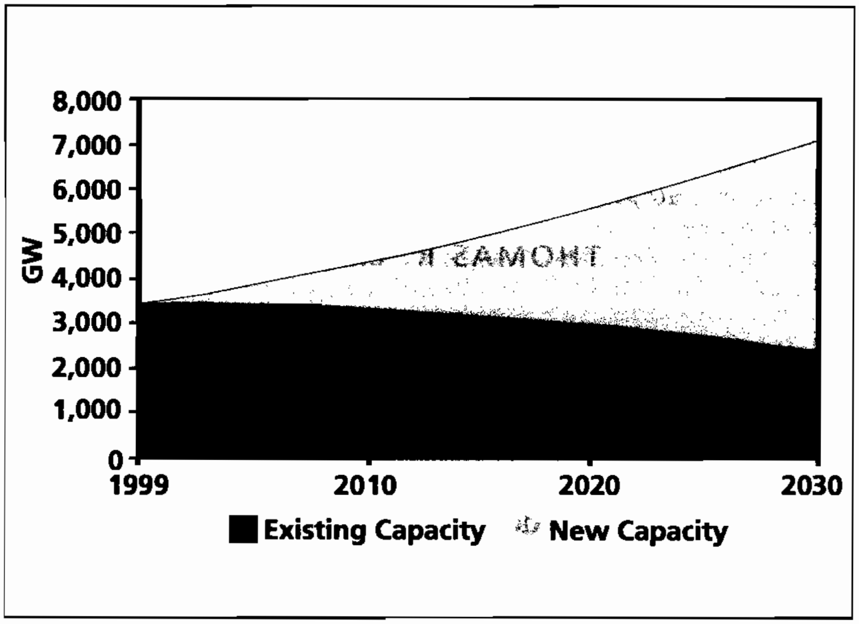

Figure 1. World installed electricity generation capacity.

The Reference Case assumes that the energy policies of each government in 2002 continue without change, a modest evolution of technology, and continued reliance on central generation of electric power, which is consistent with most existing policies and regulations. The IEA projections assume that central generation is the optimal approach, given today's technology.

The IEA report is silent on the need for (or capital cost of) new T&D, even though existing T&D is far from adequate. There were 105 reported grid failures in the U.S. between 2000 and 2003, and eleven of those outages affected more

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than a half million people.[2] U.S. consumers paid $272 billion for electricity in 2003,[3] plus power outage costs, estimated between $80 billion and $123 billion per year. Outages thus add 29 percent to 45 percent to the cost of U.S. power.[4] The T&D situation is worse in developing countries, where 1.6 billion people lack any access to electric power and many others are limited to a few hours of service per day. Satisfying expected load growth with central generation will clearly require at least comparable construction of T&D capacity.

Close examination of past power industry options and choices suggests that load growth can be met with just over half the fossil fuel and pollution associated with conventional central generation. ***We had better get this world energy expansion right.*** Consider these points:

- The power industry has not deployed optimal technology over the past thirty years.
- The universally accepted "Central Generation Paradigm" prevents optimal energy decisions.
- Decentralized generation (DG), using the same technologies used by remote central generation, significantly improves every key outcome from power generation.
- Meeting global load growth with decentralized energy can save $5 trillion of capital, lower the cost of incremental power by 35–40 percent, and reduce CO_2 emissions by 50 percent versus the IEA central generation dominated reference case.

A Brief History of Electric Generation

Figure 2 shows that United States net electric efficiency peaked in about 1910, when nearly all generation was located near users and recycled waste heat. That efficiency dropped to 33 percent over the next fifty years as the power industry moved to electric-only central generation. Industry efficiency has not improved in four decades. Technology improved, enabling conversion of fuel to electricity to rise from 7 percent at commercial inception to 33 percent by 1960. The best electric-only technology now converts more than 50 percent of the fuel to power, but the industry's average efficiency has not improved in forty-three years. No other industry wastes two-thirds of its raw material; no other industry has stagnant efficiency; no other industry gets less productivity per unit output in 2004 than it did in 1904.

Early generating technology converted 7 percent to 20 percent of the fuel to electricity, making electric-only production quite expensive. To reduce fuel costs, energy entrepreneurs, including Thomas Edison, built generating plants near thermal users and recycled waste heat, increasing net electric efficiency to as much as 75 percent. A second wave of technical progress after World War II drove electric-only efficiencies to 33 percent (after distribution losses) and increased individual plant size to between 500 and 1,000 megawatts. Central or remote generation of electricity only, while still wasting two-thirds of the input energy, became the standard. Buttressed by monopoly protection, utilities fought competing on-site generation and, by 1970, replaced all but 3 to 4 percent of local generation, ending waste heat recycling. Government regulations, developed over the first 90 years of commercial electricity, institutionalized central generation.

The third wave of technical progress should have reversed the central generation trend. Modern power plants emit only 1 to 2 percent as much nitrogen oxides as 1970 plants, come in all sizes, burn all fuels, and are good neighbors. Many technical advances make local or distributed generation technically and economically feasible and enable society to return to energy recycling, displacing boiler fuel and doubling net electric efficiency. However, protected from competition and rewarded by obsolete rules, the power industry continues to build remote plants and ignores opportunities to recycle energy.

The squares in figure 2 represent the alternative to central or remote generation. These are actual plants employing central plant generation technologies that are located near users. These combined heat and power (CHP) plants deploy the best modern electric-only technology and achieve 65 percent to 97 percent net electrical efficiency by recycling normally wasted heat and by avoiding transmission and distribution losses. United States Energy Information Agency (EIA) records show 931 distributed generation plants with 72,800 megawatts of capacity, about 8.1 percent of U.S. generation. These plants demonstrate the technical and economic feasibility of doubling U.S. electricity efficiency.

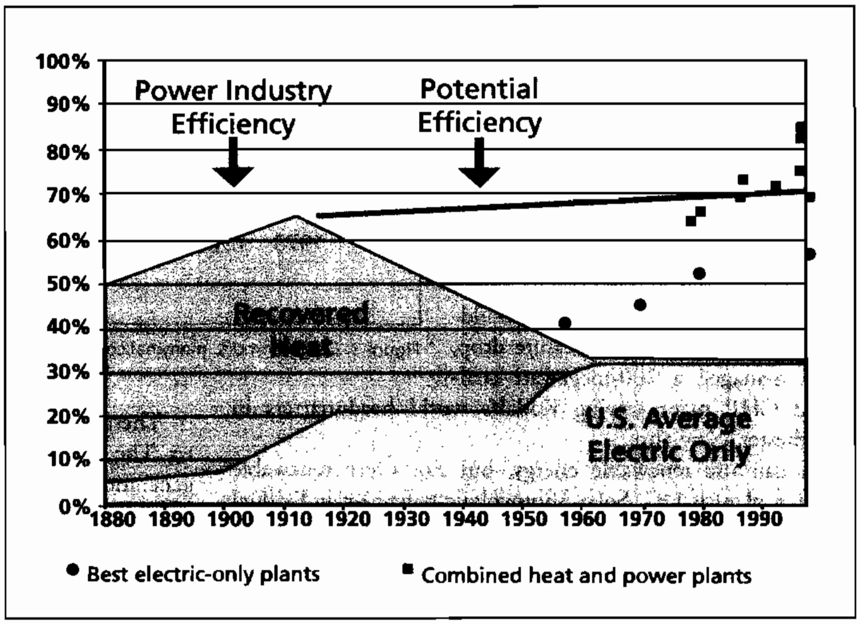


Figure 2. U.S. electricity generating efficiency, 1880 to present.

Nevertheless, the U.S. and world power industry ignores—and indeed actively fights against—distributed generation. Conventional central generation plants dump two-thirds of their energy into lakes, rivers, and cooling towers, while factories and commercial facilities burn more fuel to produce the heat just thrown away. We believe the power industry has not made wise or efficient choices, and set out to test this thesis with data.

A Flawed Worldwide Heat & Power System

To determine whether the power industry made optimal choices, we analyzed EIA data on all 5,242 reported generation plants, separating plants built by firms with monopoly-protected territories and plants built by independent power producers. We calculated what price per KWh would be required for each of four central generation technologies, built in each year, to provide a fair return on capital.[5]

We also analyzed distributed generation (DG) technology choices. Several clarifications are necessary:

- Distributed generation is any electric generating plant located next to users.
- DG is not a new concept. Edison built his first commercial electric plant near Wall Street in lower Manhattan, and he recycled energy to heat surrounding buildings.
- DG plants employ all of the technologies that are used in central generation.
- DG plant capacities range from a few kilowatts to several hundred megawatts, depending on the users' needs. We have installed 40-kilowatt back-pressure steam turbines in office buildings that recycle steam pressure drop, and managed a 200-megawatt coal-fired CHP plant serving Kodak's world headquarters in Rochester, New York.
- DG can use renewable energy, but not every renewable energy plant is DG. Solar photovoltaic panels on individual buildings or local windmills are distributed generation, while large hydro and wind farms are central generation requiring transmission and distribution (T&D).
- DG uses all fuels, including nuclear. Modern naval vessels generate power with nuclear reactors and then recycle waste heat to displace boiler fuel.

Power generated near users avoids the need for T&D. We have assumed each kilowatt of new DG will require net T&D investment equal to only 10 percent of a kilowatt, for backup services.[6] We assume DG plants require a 50 percent higher average cost of capital (12 percent versus 8 percent) due to risks and transaction costs. Industrial companies that install DG see power generation as a non-core activity and demand 35 percent to 50 percent rates of return, but this analysis focuses only on power companies' cost of capital.

Figure 3 depicts our findings. The light grey line shows the average price of power to all U.S. consumers in each year. The dashed lines show the retail price per megawatt-hour needed to fully fund new plants using four power generation technologies built as central stations, unable to recycle waste heat. (Note: Move the decimal one number left in price per megawatt-hour to equal cents per kilowatt-hour. For example, $65 per MWh is 6.5 cents per kWh.) The four highest solid lines show the retail prices per megawatt-hour needed to fully pay for power from the same technologies built near thermal users to recycle waste heat. The two lowest solid lines depict retail prices per MWh needed for power generated with recycled industrial process heat or flare gas, and power extracted from gas or steam pressure drop.

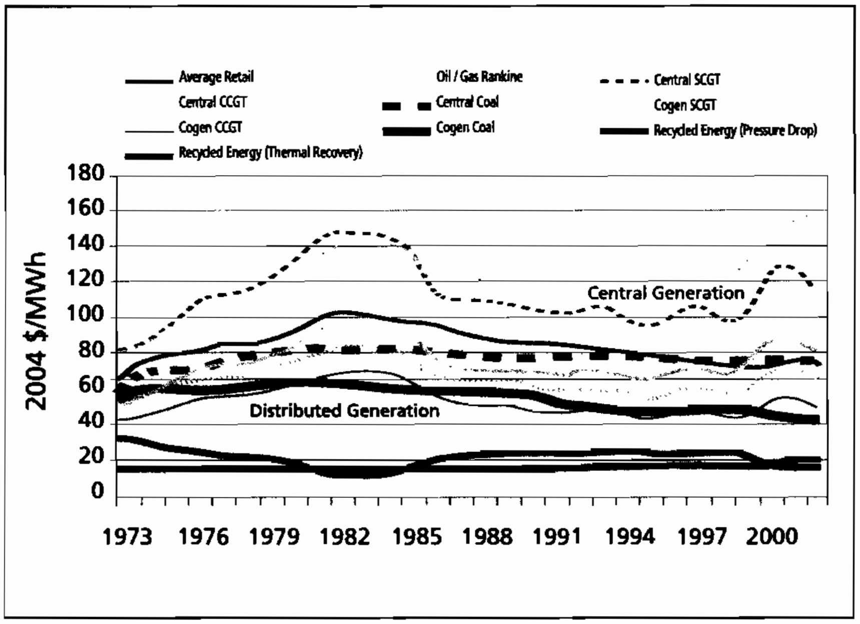


Figure 3. Long-term U.S. marginal cost of electric generation options.

Thermal plants generate steam by burning fossil fuel in boilers. The steam then drives condensing steam turbines. Thermal generation technology matured in the mid-fifties, achieving maximum electric-only efficiency of 38 percent to 40 percent, before line losses. Over the entire period, new central oil and gas thermal plants (top dashed line) required prices well above average retail. Gas turbines use a different cycle; the technology improved dramatically over the period. Simple cycle gas turbine plants (dashed line) required similar prices to gas-fired thermal plants until 1985–90, when improving turbine efficiency reduced fuel and lowered required prices. New coal plants (dashed black line) could sell power for below average retail prices each year until 1998. However, environmental rules blocked coal plants in many states.

Combined cycle gas turbine plants (CCGTs) are the same gas turbines described above, but the plants also make steam with the turbine exhaust to drive a second power generation cycle—a condensing steam turbine. The first commercial applications of CCGTs were in 1974. These plants cost less to build than an oil and gas thermal plant and initially achieved 40 percent efficiency, which rose to 55 percent by 1995.

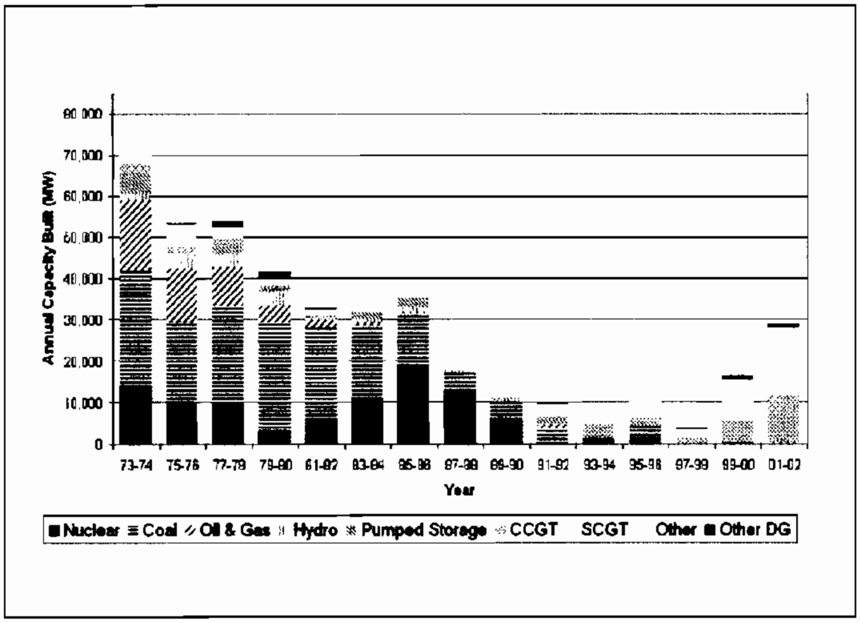


Figure 4. Annual U.S. utility additions of electricity generating capacity by technology, 1973–2002.

Distributed Generation Recycles Energy to Reduce Costs

The solid lines show retail prices required for distributed generation or DG—building the same technologies near thermal users and recycling normally wasted heat. The solid lines demonstrate the economic value of recycling energy. Burning coal in combined heat and power plants (solid black line) saves \$11 to \$27 per MWh versus burning coal in new central plants. Simple cycle gas turbine plants built near users (solid line) save \$25 to \$60 per MWh versus the same technology producing only electricity. Building combined cycle gas turbine plants near users and recycling waste heat saves even more money, reducing required costs by \$25 per MWh versus the same technology built remote from users.

The lowest-cost power avoids burning any extra fossil fuel by recycling waste energy from process industries. Process industries use fossil fuel or electricity to transform raw materials and then discard energy in three forms including hot exhaust gas, flare gas, and pressure drop. Local "bottoming cycle" generation can recycle this waste into heat and/or power. The two lowest solid lines show the retail price per megawatt-hour needed for power recycled from waste heat, flare gas, and gas or steam pressure drop after credit for displacing boiler fuel with the recovered heat. These energy-recycling plants can earn fair returns on capital selling retail power at only 25 to 50 percent of average retail prices.

Power Industry Choices for New Capacity

An ideal approach would build all possible plants requiring the lowest retail price per megawatt-hour first and then build plants with the next lowest needed retail price, etc.

To determine whether the electric power industry made optimal choices, we analyzed all power plants built since 1973. The new generation built in each two-year period by monopolies, which we defined as any utility with a protected distribution territory, is seen in figure 4. Monopoly utilities include investor-owned utilities, cooperatives, municipal utilities, and state and federally owned utilities. They collectively built 435,000 megawatts of new generation, but ignored energy recycling, even though it was always the cheapest option. They continued to build oil and gas thermal plants long after CCGT plants were a cheaper central option. Monopoly utilities were slow to make optimal choices among central plant technologies and completely ignored the more cost-effective distributed use of the same technologies.

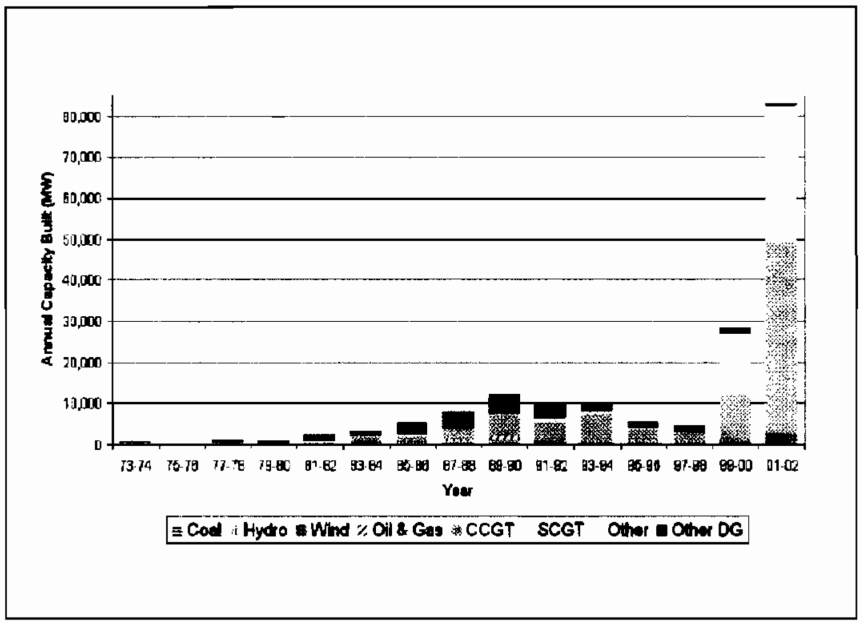


Figure 5. Total U.S. independent power producers utility additions of electric generating capacity by technology, 1973–2002.

Figure 5 shows the 175,000 MW of new generation built by independent power producers (IPP's) since 1973. Most new

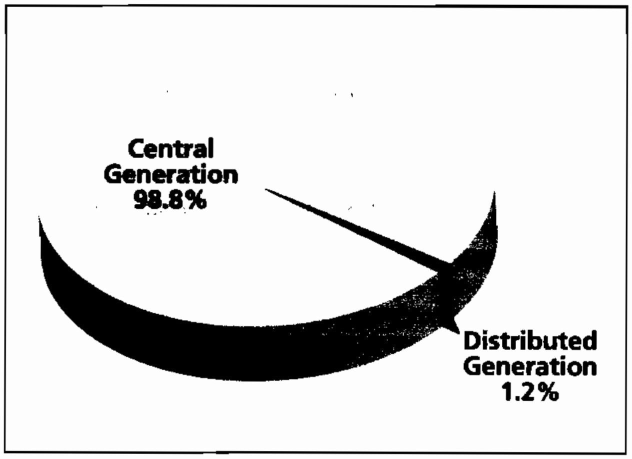


Figure 6. Total generation capacity built by U.S. electric utilities, 1973–2002.

IPP plants were distributed generation and/or combined cycle plants until the last four years. The price spikes of 1998–2000 apparently induced IPP companies to install simple cycle gas turbines for peaking. Prior to 1978 passage of the Public Utility Policy Regulatory Policy Act (PURPA) it was illegal to build generation as a third party. Between 1978 and the law change in 1992, IPPs were allowed to build qualifying facilities—those that recycled at least 10 percent of the fuel's energy for heat use, or utilized certain waste fuels. After 1992, IPPs could legally build remote electric-only generation plants.

For another view of industry choices, we divided plants built since 1973 into those recycling and not recycling energy. Generating plants that recycle energy must be near thermal users or near sources of industrial waste energy. Figure 6 shows that only 1.2 percent or 5,000 of the 435,000 megawatts of new generation built by monopolies over the thirty-year period recycled energy. We doubt that these choices would be profitable in a competitive marketplace.

Independent power producers built 34 percent of their total capacity as DG plants, at or near users. Figure 7 depicts the mix of central and distributed power built by IPPs since 1978.

Finally, we estimated the potential generation from the least-cost options—those plants that recycle industrial process waste energy. EPA aerometric data and other industry analyses suggest that U.S. industrial waste energy would power 40,000 to 100,000 megawatts with no incremental fossil fuel and no incremental pollution.[7] However, EIA plant data show only 2,200 megawatts of recycled industrial energy capacity, 2.2 percent to 5 percent of the potential.[8]

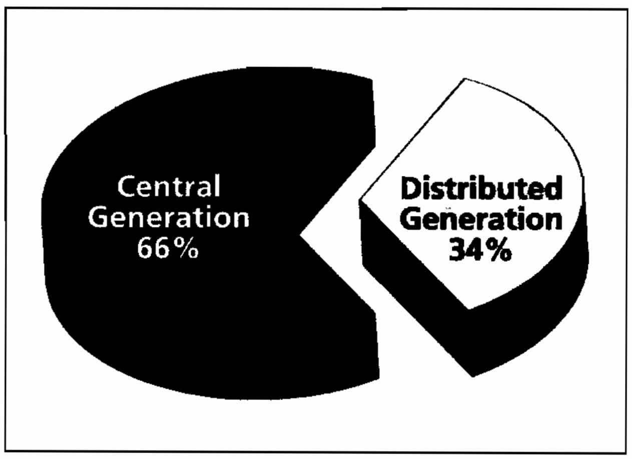


Figure 7. Generation capacity built by U.S. electric IPPs, 1973–2002.

It seems clear that the power industry has made poor choices that have increased cost and decreased efficiency. These data show that utilities eschewed least-cost generating technologies, effectively increasing prices to all customers.

Meeting Expected U.S. Load Growth with Local Generation

Our colleagues built a model to determine the best way to satisfy projected load growth for any nation over the next two decades.[9] The model incorporates relevant factors for central and distributed electric generation technologies, including projected improvements in cost, efficiency, and availability of each technology. The model assumes new central generation will require 100 percent new transmission and distribution and new decentralized generation will require new T&D equal to 10 percent of added generating capacity. The model assumes 9 percent line losses for central power, equal to U.S. losses for 2002, and 2 percent net line losses for DG power.

Although the future surely includes some mix of central and decentralized generation, the model calculates the extreme cases of meeting all load growth with central generation, or meeting all growth with decentralized generation. Local generation that recycles energy improves every important outcome versus full reliance on central generation. Figure 8 compares the extreme cases. Full reliance on DG for expected U.S. load growth would avoid \$326 billion in capital by 2020, reduce incremental power costs by \$53 billion, NO_x by 58 percent, and SO_2 by 94 percent. Full DG lowers carbon dioxide emissions by 49 percent versus total reliance on new central generation.

Impact of Generating 2020 Load Growth with Central or Decentralized Generation

	100 percent CG	100 percent DG	Savings	Percent Change
Total Capital Cost (Capacity + T&D) Billions of Dollars	\$831	\$504	\$326	39 percent
2020 Incremental Power Cost Billions of Dollars	\$145	\$92	\$53	6 percent
2020 Incremental Power Cost Cents/KWh	8.61	5.47	3.14	36 percent
Emissions from New Load Thousand Metric Tonnes				
NO_x	288	122	166	58 percent
SO_2	333	19	314	94 percent
PM10	22	12	9	43 percent
Million Metric Tonnes CO_2	776	394	381	49 percent

Figure 8. Decentralized generation as a percentage of total U.S. generation.

Extrapolating U.S. Analysis to the World

We lack the data to run the U.S. model for the world, but have taken the percentage savings to be directionally correct and applied them to the IEA load growth projections through 2030. Detailed analysis by others will undoubtedly refine the estimates, and there will be some mix of central and decentralized generation. The analysis shows the extreme cases to provide guidance.

Figure 9 shows expected world load growth with conventional central plants that convert 100 units of fuel into 67 units of wasted energy and 33 units of delivered power. The text at the bottom reflects IEA's projected capital cost for 4,800 gigawatts of new generation, totaling $4.2 trillion. The International Energy Agency was silent on T&D, so we used estimates made for the United States Department of Energy on the all-in cost per kW of new transmission to forecast $6.6 trillion cost for new wires and transformers. Assuming U.S. average line losses (which are significantly lower than developing country line losses), 9 percent of the capacity will be lost, leaving 4,368 gigawatts delivered to users. To achieve the IEA Reference Case with central generation, the world must invest $10.8 trillion capital, roughly $2,500 per kW of delivered capacity.

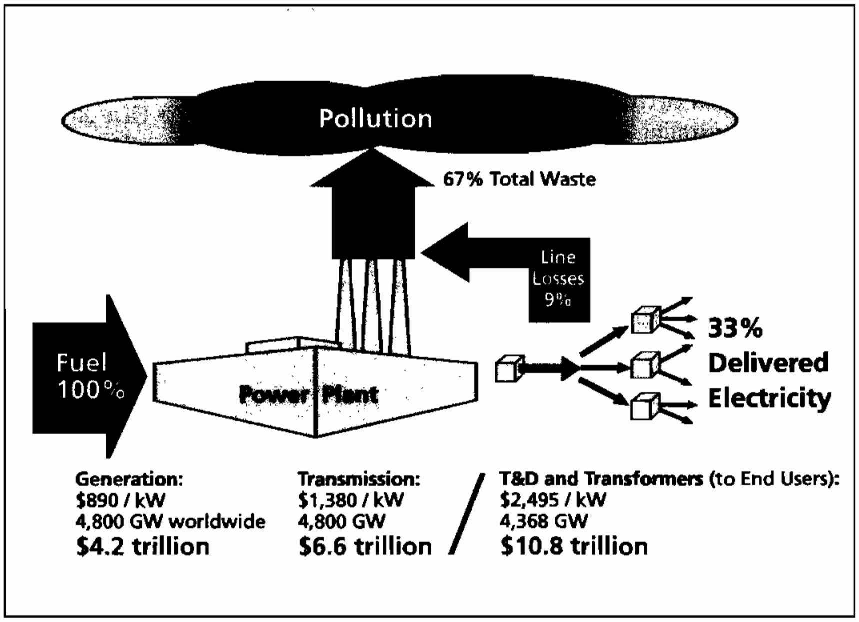


Figure 9. Conventional central generation flowchart.

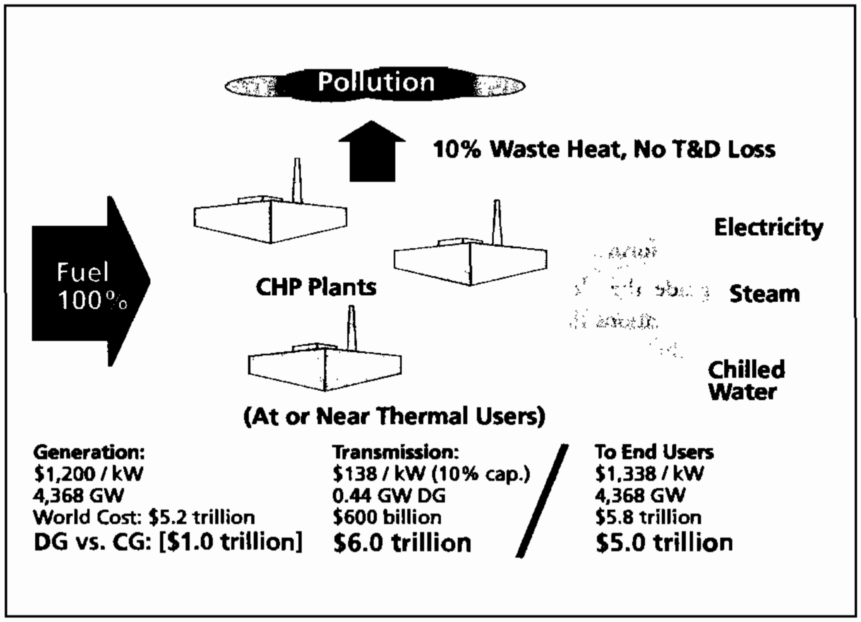


Figure 10. Combined heat and power flowchart.

Meeting IEA Reference Case load growth with decentralized generation will lower the need for redundant generation. An analysis by the Carnegie Mellon Electric Industry Center suggests building only 78 percent of the 4,800 gigawatts as DG would provide equal or better reliability.[10] However, in developing economies, reliability may not be the driver. To be conservative, we have ignored the potential reduction in generation due to increased reliability inherent in larger numbers of smaller plants in the DG case. However, we did reduce required generation for the DG case to 4,368 GW, since there are no net line losses.

Figure 10 depicts the process of meeting expected world load growth with distributed generation. We estimated average capital costs for decentralized generation of $1,200 per kW, $310 more capital cost than a kilowatt of new central generation. Even with 9 percent less DG capacity, the capital costs for generation increase to $5.2 trillion, $1.0 trillion more than building central plants. Looking only at generation costs, DG is not competitive. However, the full decentralized generation case requires only 430 GW of new T&D, costing $0.6 trillion, a $6 trillion savings on T&D. *End users receive 4,638 GW in both cases, but society invests $5 trillion less for the DG case.*

Everyone knows that "you get what you pay for." What does the world give up by selecting a $5 trillion cheaper approach to meet projected electric growth? We extrapolated U.S. analysis to the IEA Reference Case and found the world would give up the following by adopting the cheaper DG case:

- Consume 122 billion fewer barrels of oil equivalent (half of known Saudi oil reserves)

- Lost fossil fuel sales of $2.8 trillion
- Lost medical revenues from air pollution-related illnesses
- Potentially lost savings if governments opt to supply electric services to entire population instead of leaving 1.4 billion people without electric access
- Less global warming due to 50 percent less CO_2 emissions.

Recommended Actions

If this analysis survives critical review, then what policy reforms will steer the power industry toward optimal decisions, given available technology? We offer two potential approaches, hoping to start the policy debate.

Distributed generation of electricity saves the world $5 trillion in capital investment while reducing power costs by 40 percent and cutting greenhouse gas emissions in half. There are important implications for worldwide energy policy if this analysis is correct.

Comprehensive Reform

Governments guide the electric industry with many rules, mandates, and limitations that collectively block competition and innovation, thus causing excessive costs and fuel usage. Small regulatory changes may nudge the power industry to slight course corrections, but are unlikely to break the central generation paradigm and optimize generation.

Immediately eliminating all current barriers to efficiency would cause the electric power industry to make better decisions. Each government could examine every rule that affects power generation and delivery and ask whether the social purpose behind that rule still exists. Then each state or country could enact comprehensive legislation that we term the Energy Regulatory Reform and Tax Act (ERRATA), to correct all of the mistakes in current law. ERRATA would deregulate all electric generation and sales, modernize environmental regulations to induce efficiency, and change taxation to reward efficiency.[11] Sadly, ERRATA legislation probably will not pass except in response to deepening environmental and economic pain.

Actionable Reform, National Fossil Fuel Efficiency Standards

A second possible approach simply rewards all fossil efficient power and penalizes fossil inefficient power. Each government could enact a Fossil Fuel Efficiency Standard covering all locally used electricity, regardless of origin. This standard does not favor fuels, technologies, or participants. Here are the essential elements:

- Give all delivered megawatt-hours an equal allowance of incremental fossil fuel, regardless of age of plant, technology or ownership. Start with the national average fossil fuel per MWh for the prior year.
- Spread allowances over all generation of each owner, allowing owners to comply by increasing efficiency of existing plants, deploying new highly efficient plants, or purchasing fossil allowances from others.
  - Reward plants requiring little or no fossil fuel, such as solar, wind, hydro, nuclear, and industrial waste energy recycling, by allowing them to sell fossil fuel credits.[12]
  - Penalize fossil inefficient plants by forcing them to purchase allowances for each MWh produced.
  - Base allowances on delivered power to incorporate T&D losses from central generation.
  - Credit displaced fuel to CHP plants that recycle heat.
  - Force all generators to purchase adequate allowances or close their plants to ensure that the total allowance trading is economically neutral.
  - Reduce the fossil fuel allowances per MWh each year according to a schedule.
- Adjust the schedule downward each year to correct for growth in total power delivered, guaranteeing that the total fossil fuel use will drop.

A Fossil Fuel Efficiency Standard would steer the power industry toward optimal choices. This will reduce power costs and emissions, which will improve local standard of living and improve the competitive position of local industry. Other states and nations will follow suit.

Conclusion

We have attempted to frame the consequences of meeting energy load growth with conventional central generation or deploying decentralized generation that recycles waste energy. The DG case saves the world $5 trillion in capital investment while reducing power costs by 40 percent and cutting greenhouse gas emissions in half. There are interesting implications for worldwide energy policy if this analysis stands up to critical review.

We hope readers and others will spell out concerns or suggest corrections so we can collectively improve the analysis of optimal future power generation. The needed policy changes are deep and fundamental and require a consensus about the best way to proceed. Together we might be able to change the way the world makes heat and power.

Notes

1. The IEA has issued an annual "World Energy Outlook" series since 1993. The publication projects many facets of the energy industry thirty years ahead. The projections are based on a "Reference Scenario that takes into account only those government policies and measures that had been adopted by mid-2002. A separate Alternative Scenario assesses the impact of a range of new energy and environmental policies that the OECD countries are considering."

2. *Energy Information Administration/Electric Power Monthly*, May 2004.

3. *Energy Information Administration/Monthly Energy Review*, June 2004.

4. Joseph Eto, of the Lawrence Berkeley National Laboratory, in a speech to NARUC, says outages cost the U.S. $80 billion per year. The EPRI Consortium for Electric Infrastructure to Support a Digital Society (CEIDS), *The Cost of Power Disturbances to Industrial & Digital Economy Companies*, June 2001, states power outages and other power quality disturbances are costing the U.S. economy more than $119 annually.

5. We assembled historical data for four central generating technologies—oil and gas-fired thermal plants (Rankine cycle), coal fired thermal plants, simple-cycle and combined-cycle gas turbines. Data for each technology and each year include capital costs per kW, load factor, and efficiency. We assumed a 25-year life to calculate annual capital amortization and the future wholesale price per MWh that would yield an 8 percent weighted average return on capital. Since new central generation requires new T&D, we converted estimates of $1260 per kW for T&D in 2000 and adjusted for inflation, then assumed a 35-year life for T&D to calculate required T&D charges. EIA did not keep line loss statistics prior to 1989, so we estimated prior years slightly below the current 9 percent losses. Summing produces the retail price needed for power from a central plant using a specific technology installed in that specific year. Finally, we converted everything to 2004 dollars.

6. Typical DG plants employ multiple generators with expected unplanned outages of 2 percent to 3 percent each. The probability of complete loss of power is found by multiplying expected unit unplanned outages by each other. Given the existing 10,286 generators operating in the U.S. that are less than 20 megawatts of capacity, and the expectation, with barriers removed, of many DG plants inside every distribution network, spare grid capacity equal to 10 percent of installed DG should be more than adequate to cover unplanned outages.

7. *Recycled Energy: An Untapped Resource*, Casten and Collins, 2002; see www.primaryenergy.com.

8. Energy Information Administration, *Annual Energy Review 2002*, October 2003.

9. The "Optimizing Heat and Power" model has been adopted by the World Alliance for Decentralized Energy (WADE) and is being used by the European Union, Thailand, Nigeria, Canada, Ireland, and China to ask the best way to satisfy expected load growth. For model descriptions, contact Michael Brown, Director, at info@localpower.org.

10. Hisham Zerriffi. Personal communication. See *Distributed Resources and Micro-grids* by M. Granger Morgan of the Department of Engineering and Public Policy, Carnegie Mellon University, Sept. 25, 2003, for detailed analysis of how DG provides reliability with less spare capacity.

11. See Casten, Thomas R. *Turning Off The Heat* 1998, Prometheus Books, chapter 10 for a more complete description of ERRATA.

12. Producers of electricity are given fossil fuel usage credits, meaning they are allowed to use a given amount of fossil fuels corresponding to efficiency, size of unit and other environmental parameters. Thus, the higher the efficiency of a company's unit, the less fossil fuel credits that company needs to use. The highly efficient plants and generation plants using a non-fossil fuel energy such as solar, wind, or hydro power would not need the full allowance and could sell the unused portion to less efficient fossil fueled plants. Such a system would provide added economic value to the efficient and non-fossil fueled plants and economic penalties to the inefficient fossil fueled plants. ☐

Glossary of Abbreviations and Acronyms

CCGT—Combined-cycle gas turbine—refers to a power plant that utilizes both the Brayton (gas-turbine) cycle and the Rankine (steam) cycle. The exhaust from the gas turbine is used to generate the energy for the Rankine cycle.

CHP—Combined heat and power—the simultaneous and high-efficiency production of heat and electrical power in a single process.

CO_2—Carbon dioxide—a gas produced by many organic processes, including human respiration and the decay or combustion of animal and vegetable matter.

DG—Decentralized/distributed generation—a system in which electrical power is produced and distributed locally near users, largely avoiding T&D.

DOE—Department of Energy—the federal agency that oversees the production and distribution of electricity and other forms of energy.

EIA—Energy Information Administration—the statistical and data-gathering arm of the Department of Energy.

EPA—Environmental Protection Agency—the agency that oversees and regulates the impact of, among other things, the production of energy on the environment of the United States.

ERRATA—Energy Regulatory Reform and Tax Act—a plan to deregulate the production and distribution of electricity, to update environmental laws regarding energy production, and to alter the existing tax structures.

GW—Gigawatt—one billion watts.

GWh—Gigawatt hour—the amount of energy available from one gigawatt in one hour.

IEA—International Energy Agency—a twenty-six member union of national governments with the goal of securing global power supplies.

IPP—Independent power producers—companies that generate electrical power and provide it wholesale to the power market. IPPs own and operate their stations as non-utilities and do not own the transmission lines.

KW—Kilowatt—1,000 watts (one watt being the amount of power necessary to move one kilogram one meter in one second).

KWh—Kilowatt hour—the amount of energy available from one kilowatt in one hour.

MW—Megawatt—one million watts.

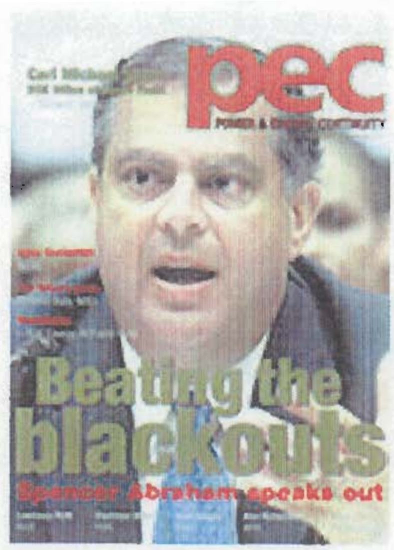
MWh—Megawatt hour—the amount of energy available from one megawatt in one hour.

NO_x—Nitrogen oxide—assorted oxides of nitrogen, generally considered pollutants, that are commonly produced by combustion reactions.

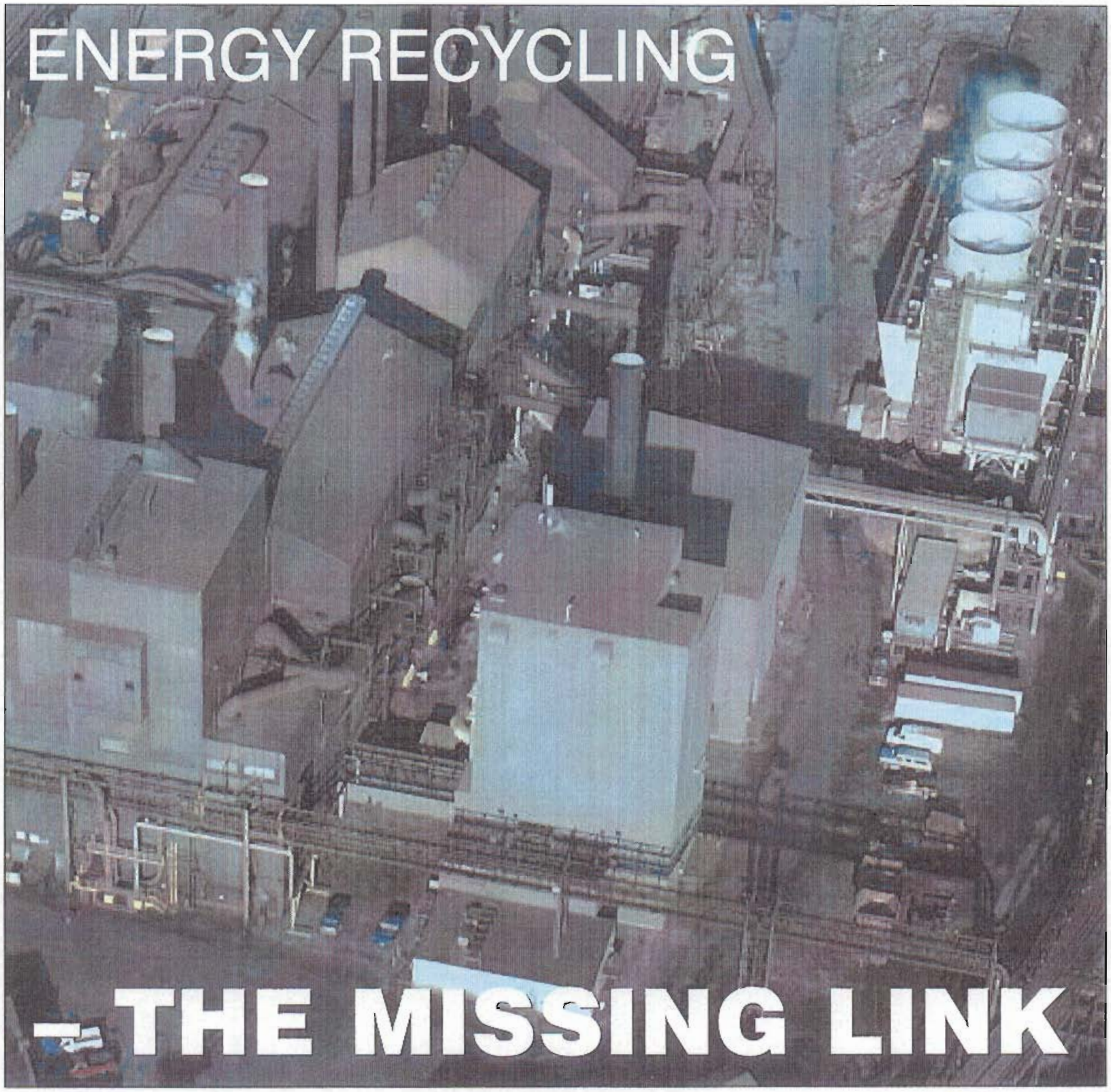
PM10—Particulate matter in the atmosphere that is between 2.5 and 10 micrometers in size.

PURPA—Public Utility Regulatory Policy Act—an act of Congress that was intended to reduce American dependence on foreign oil through the encouragement of the development of alternative energy sources and the diversification of the power industry.

T&D—Transmission and distribution—the means by which electricity travels from the generating plant(s) to its end users.


pec
Beating the blackouts
Spencer Abraham speaks out

ENERGY RECYCLING – THE MISSING LINK



by Thomas R Casten

The US faces severe energy related problems, including over-taxed transmission, high natural gas prices, regions with air quality problems, and concerns about greenhouse gas emissions.

The economy is increasingly vulnerable to OPEC, extreme weather and terrorists, and power quality – appropriate for the last century's electric motors – is inadequate for today's digital economy. An Electric Power Research Institute (EPRI) study, carried out before the 14 August 2003 blackout, put the cost of power quality problems to the US economy at US$119 billion per year.[1] US industry is understandably concerned.

CURRENTLY PROPOSED SOLUTIONS

EPRI says it will cost US$226 billion to shore up the electrical transmission system. Faced with dwindling low-cost gas fields in the continental US, the gas industry proposes more drilling in Alaska, with long pipes to the US and LNG terminals to handle expensive gas imports. State and federal environmental agencies, seeking cleaner air, mandate expensive scrubbers for the nation's aging fleet of central generation plants. President Bush refuses to set limits on greenhouse gas emissions, claiming this will cause economic disruption. However, these conventional approaches all start with the same flawed world view – that central generation of electricity is optimal. Instead of improving electric generation efficiency, each group urges government to throw money at the problem, raising energy prices and causing further loss of industrial jobs. We need better solutions.

Energy recycling is the missing link – a fresh approach that addresses all energy related problems while saving money, reducing pollution, reducing vulnerability, and providing new jobs by creating new revenue streams to basic industry for sale of their waste energy. And government can induce energy recycling with no cost to the taxpayer by simply modernizing regulations and removing current barriers to efficiency.

ENERGY RECYCLING BASICS

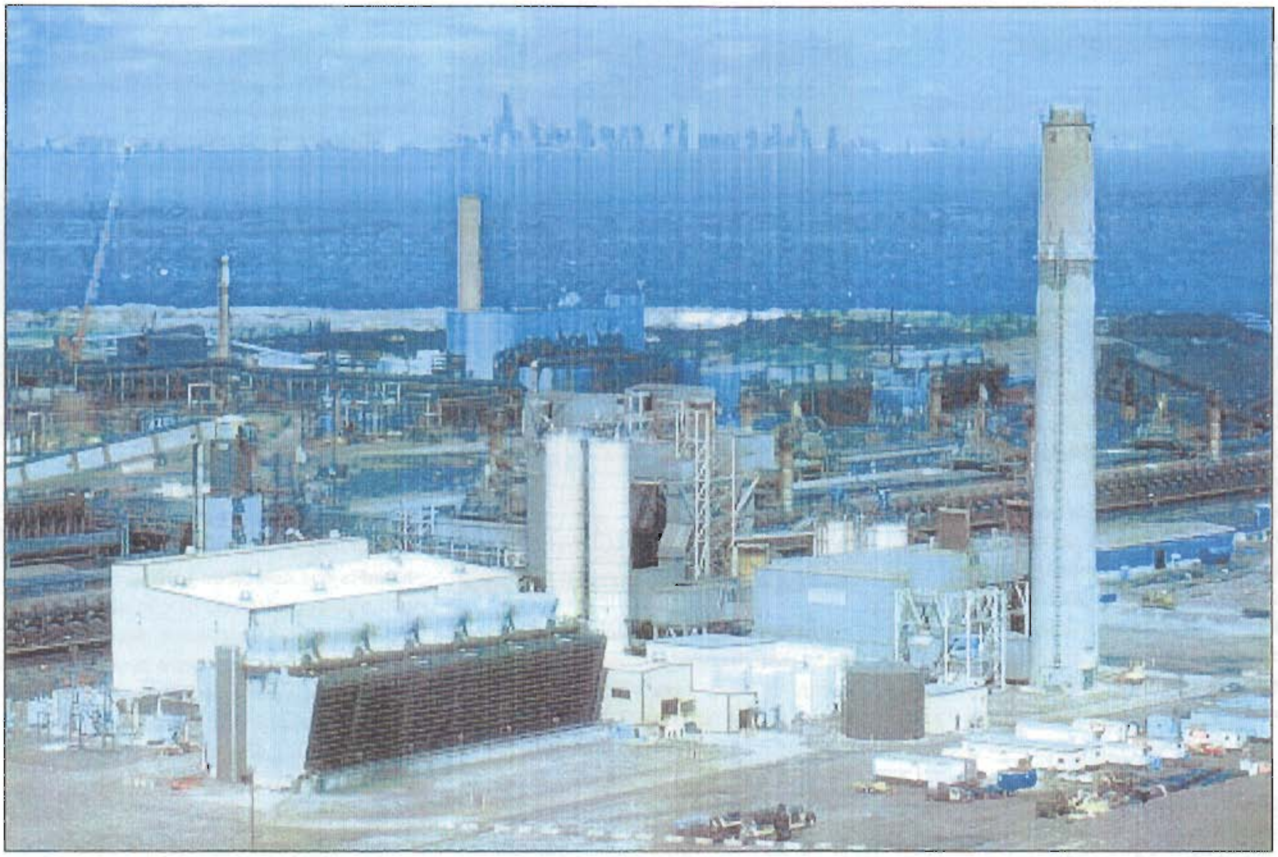
Manufacturers of most products, including electricity, vent significant byproduct energy. Much of this waste can be economically recycled into electricity and useful thermal energy. Recycled energy adds no pollution and displaces the pollution and cost from fossil fuel that would have been burned to produce the same energy. Average US central generation of electricity, which accounts for over 90 percent of US power, is needlessly inefficient and dirty, precisely because remote plants cannot recycle

byproduct waste heat. Average US central generation delivers end users one unit of energy for every three units of input fuel; this miserable 33 percent efficiency has not improved in 43 years. The collective energy thrown away by US central electric generation plants could displace nearly half of the nation's boiler fuel, but it is uneconomic to transport heat over long distances. Each decision to build new, isolated central generation is a 25-40 year decision to waste energy.

The US electric industry wastes 20 quadrillion Btu's each year, equal to 20 percent of the nation's 100 quads of total energy use. Simply building new electric generation plants near thermal users would allow the plants to economically recycle at least half of this waste, cutting the nation's total fuel use by 10 percent. In spite of many barriers, US energy innovators have managed to build about 65,000 megawatts (eight percent of total generation) of decentralized plants that recycle waste heat. A recent study sought the best way to meet the expected US 43 percent electric load growth over the next two decades and compared serving the new load with decentralized or with central generation.[2] The conclusion: decentralized generation cuts power costs by 40 percent compared to central generation.

Decentralized CHP plants cost more per kilowatt of generating capacity than new central plants, a seeming disadvantage. But this comparison yields the wrong conclusion. Total capital cost for new central generation includes both

"Each decision to build new, isolated central generation is a 25-40 year decision to waste energy"



Cokenergy at Ispat Inland Steel, East Chicago, Indiana
Note: City of Chicago across Lake Michigan

the generating plant and new T&D investments. Centrally generated power must be transformed to higher voltages, must travel through long, leaky wires and then be transformed back to user voltages. This process 'eats' one kilowatt hour in 10. Since only 90 percent of centrally generated power reaches end users, society must build 1.1 megawatts of central generation and 1.1 megawatts of new T&D for each megawatt of load. An alternative is to simply build one megawatt of distributed generation at the load. The study referenced above found that decentralized generation would avoid nearly US$400 billion of capital investment over the next 20 years, reducing needed capital investment from US$900 billion to US$500 billion.

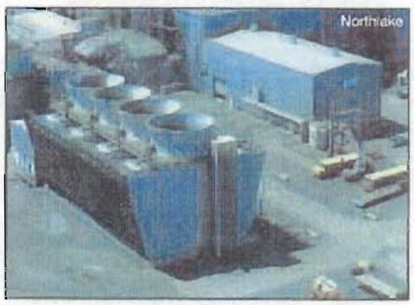
Decentralized generation, by recycling waste energy and avoiding line losses, dramatically reduces air pollution versus central plants. Emissions of NOx, SO_2 and particulate matter (PM10) are respectively 58 percent, 68 percent and 43 percent lower in the decentralized generation scenario than in the central generation scenario. Carbon dioxide emissions dropped by 49 percent with decentralized power. Recycling energy is the missing link.

RECYCLING INDUSTRIAL WASTE ENERGY

A second option is to recycle industrial waste heat, waste fuel, and pressure drop into heat and power. Visit a steel mill, refinery, chemical or glass factory on a cold day and you will see vast clouds of vapor – wasted energy. EPA gas flare data identifies roughly 88,000MWh of wasted energy every hour. Recycling this waste could power 22,000MW of electric generation, the equivalent of 22 nuclear plants. Produce combined heat and power with flare gas to net 66,000MW of heat and power. We estimate that 10,000MW could be produced without any new fuel by extracting power from the steam and gas pressure drop found throughout industry and on university and medical campuses. Recycling hot exhaust might yield 10,000 to 50,000 more megawatts of useful energy.[3]

RECYCLED ENERGY IS CLEAN ENERGY

No incremental fossil fuel is burned and no incremental air pollution is



produced when waste energy is recycled into heat and power. Consequently, recycled energy is every bit as environmentally friendly as heat and power from renewable energy sources, including solar energy, wind and biomass. Recycled energy should therefore qualify for every renewable energy incentive.

RECYCLED ENERGY CASE STUDIES

Building recycled energy projects has been incredibly difficult, because utilities typically oppose onsite generation, fearing loss of revenue and potential weakening of the 'electric monopoly' logic. But in 1994, NiSource, parent of Northern Public Service Company (NIPSCO), took a more enlightened view. NIPSCO's steel customers were in trouble. Legacy costs for retirees' health and pension, intense foreign competition, and aging production facilities had combined to slash steel industry profits and cash flow. There were, in every steel plant, huge waste energy flows that could be recycled to cut costs, but the steel industry had more urgent demands for capital in core production facilities.

NiSource formed a subsidiary, Primary Energy, and invested US$300 million between 1994 and 2003 in six energy projects with capacity to recycle roughly 900MW of heat and power from steel plant waste heat and blast furnace gas. Myriad rules stood in the way, but Primary Energy persevered. Indiana law prohibits any third party from selling electricity to a host, so Primary Energy crafted tolling arrangements under which US Steel, International Steel Group (ISG) and Ispat Inland pay to convert their waste energy to heat and power, which they use. NIPSCO offered electricity buy/sell arrangements at fair prices instead of demanding predatory backup power charges. When steel company credit was insufficient to support financing, NiSource bet on its customers and guaranteed loans. Union steelworkers were hired by the steel companies to operate each project, with Primary Energy providing supervisory engineers.

All three steel companies are much healthier today and currently produce and sell every possible ton of steel. Recycled energy has played an important role in this economic turnaround. The steel companies are collectively saving US$100 million per year and have reduced emissions and improved their power reliability.

The six recycling projects eliminate 19,000 tons of NOx, 22,000 tons of SO_2 and seven million tons of carbon dioxide emissions per year and have won several environmental awards.

Three projects, one at each company, burn blast furnace gas to make high-pressure steam, which drives extraction/condensing steam turbine generators. The projects are capable of 50MW to 160MW of electric generation and supply most of the mill's requirements for process and heating steam.

A conventional GE gas turbine feeds US Steel's cold rolled tin plant. The gas turbine exhaust is recycled to produce high-pressure steam that drives a steam turbine. Then the remaining energy is recycled again to heat 1600 gallons per minute of softened water used to wash the steel. By recycling waste heat, the plant achieves 2.5 times the efficiency of average central generation and saves money.

Hot exhaust from 368 coke ovens is converted to high-pressure steam by 16 heat recovery steam generators to drive a 95-megawatt electricity generator and provide 300,000 to 600,000 pounds of process steam.

DG as % of total US generation.

	100% CG	100% DG	Savings	% change
Total capital cost (capacity + T&D) Billons of dollars	$904	$506	$397	44%
2020 incremental power cost Billions of dollars	$153	$92	$61	40%
2020 incremental power cost Cents/kWh	9.13	5.48	3.64	40%
Emissions from new load Thousand metric tones				
NO_x	288	122	166	58%
SO_2	250	80	170	68%
PM10	22	12	9	43%
Million metric tones CO_2	777	394	383	49%

Impact of generating 2020 load growth with central or decentralized generation

Thomas R Casten has spent 30 years developing decentralized heat and power as founding President and CEO of Trigen Energy Corporation and its predecessors from 1977 through 2000, founding Chairman and CEO of Private Power from 2001 to 2003, and currently as Chairman and CEO of Primary Energy, a company specializing in recycling energy.

Casten has served as President of the International District Energy Association and has received the Norman R. Taylor Award for distinguished achievement and contributions to the industry. He currently serves on the board of the American Council for an Energy-Efficient Economy, the Center for Inquiry, and the Fuel Cell Energy Board, and is the Chairman of the World Alliance for Decentralized Energy (WADE).

For more information, please e-mail: tcasten@primaryenergy.com

Blast furnace stove exhaust contains significant amounts of energy, but it is not hot enough to be economically recycled as electricity. Instead, Primary Energy uses the heat to dry coal for injection into North America's largest blast furnace. This has enabled Ispat Inland to significantly reduce natural gas and coke usage.

There are myriad energy recycling opportunities in the kilowatt size range. Turbosteam of Turner Falls, Massachusetts, installed a 50kW backpressure turbine to recycle steam pressure drop at the Suffolk County Jail in Boston, Massachusetts. The jail purchases medium pressure steam from Trigen Boston's district steam system and historically deflated the steam to low pressure with a valve. Since the 1997 installation of a backpressure turbine generator, the jail has enjoyed free electricity. They purchase no added steam, but send cooler condensate to the sewer.

ARE US$20 BILLS LYING ON THE GROUND?

Economists assert that there are no US$20 bills lying on the ground in a free market. Under this theory, it will be impossible to repeat what Primary Energy has done, since recycling energy innovators must have already captured all of the economic opportunities to recycle waste energy. Policy makers who support massive expenditures to fix energy problems must believe that there are no options that reduce pollution and vulnerability and save money. We think they are wrong.

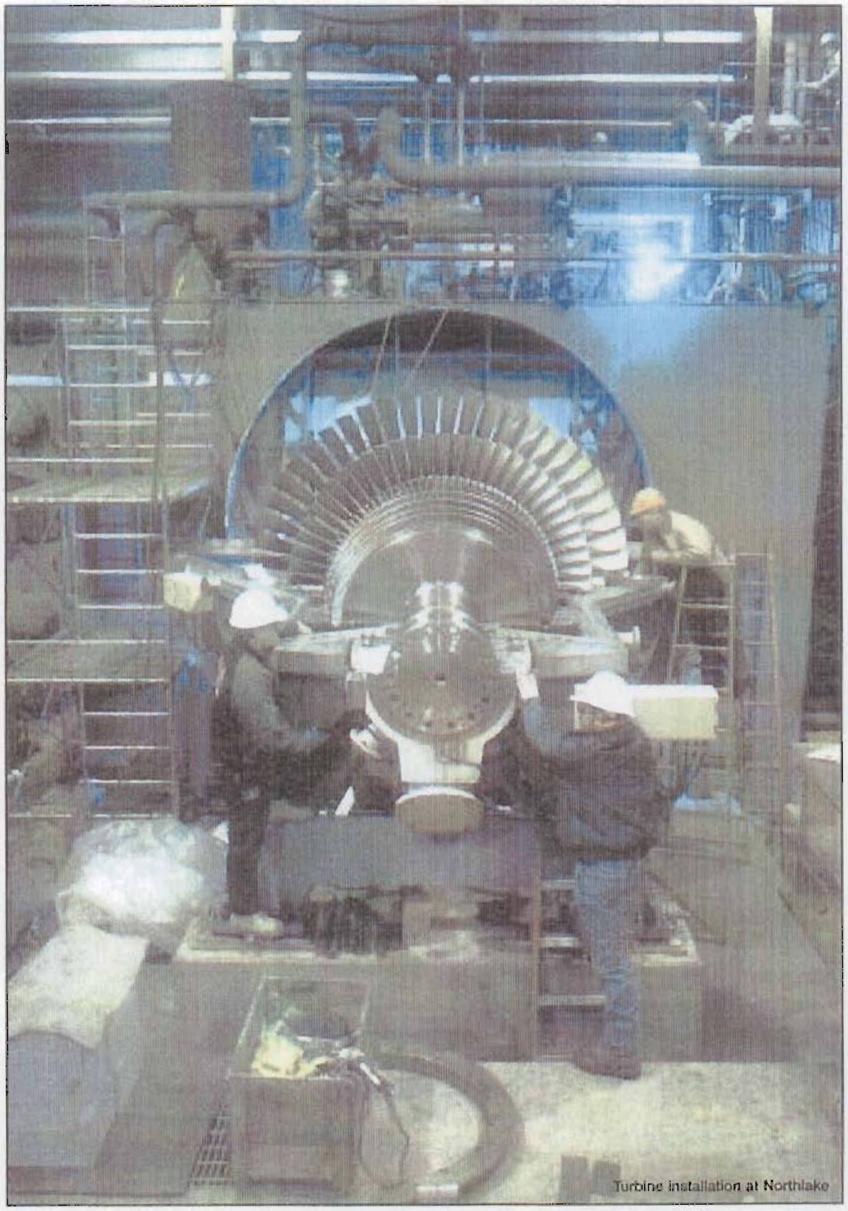
The electric market is anything but free, and obsolete regulations make it largely illegal and/or uneconomic for would-be energy recycling innovators to pick up the 'US$20 bills'. These barriers are artifacts of the history of the 120-year-old electric industry.

Electricity, arguably the most important invention of all time, became a commercial reality in 1880 in NYC and San Francisco. Word spread rapidly and every community wanted to electrify as quickly as possible. Early technology favored remote generation (hydroelectric plants and yesterday's coal plants) and there were, in the early days, substantial economies of scale. Assuming technology would always favor remote plants and that there would always be economies of scale in generation, governments all over the world decided to restrict competition and made Faustian bargains with electric entrepreneurs. In exchange for a monopoly in perpetuity, the entrepreneurs agreed to rapidly electrify each community. They were allowed fair returns on capital on the condition that they would pass all efficiency gains to the public in order to prevent excessive profits. This protected status lowered the cost of capital, making electricity more affordable. Everyone was expected to live happily ever after and, for years, real prices per kilowatt-hour declined.

For years, the industry worked hard to lower costs to lure customers away from self-generation, gas lighting and muscle power; and a world view grew that central generation is the optimal way to produce and deliver power.

But technology marched on, resulting in ever more reliable, efficient and cost-effective smaller generation plants. Add the advantages of energy recycling, avoidance of line losses, reduced vulnerability and improved power quality, and the conclusion is inescapable – decentralized generation wins.

Netherlands, Finland and Denmark each recognized the value of decentralized generation 20 years ago and each country now generates over 40 percent of their nation's power onsite with maximum energy recycling. These countries use 50 percent less fuel per kWh than the US and have consequently maintained robust industrial production. Portugal saw the light and now offers prices for power from decentralized plants that include avoided central plant fuel and capital, avoided T&D capital and line losses, and avoided pollution. India just reversed 50-year-old policies and now offers long-term contracts at over six cents per kWh for power made at sugar cane factories from bagasse.

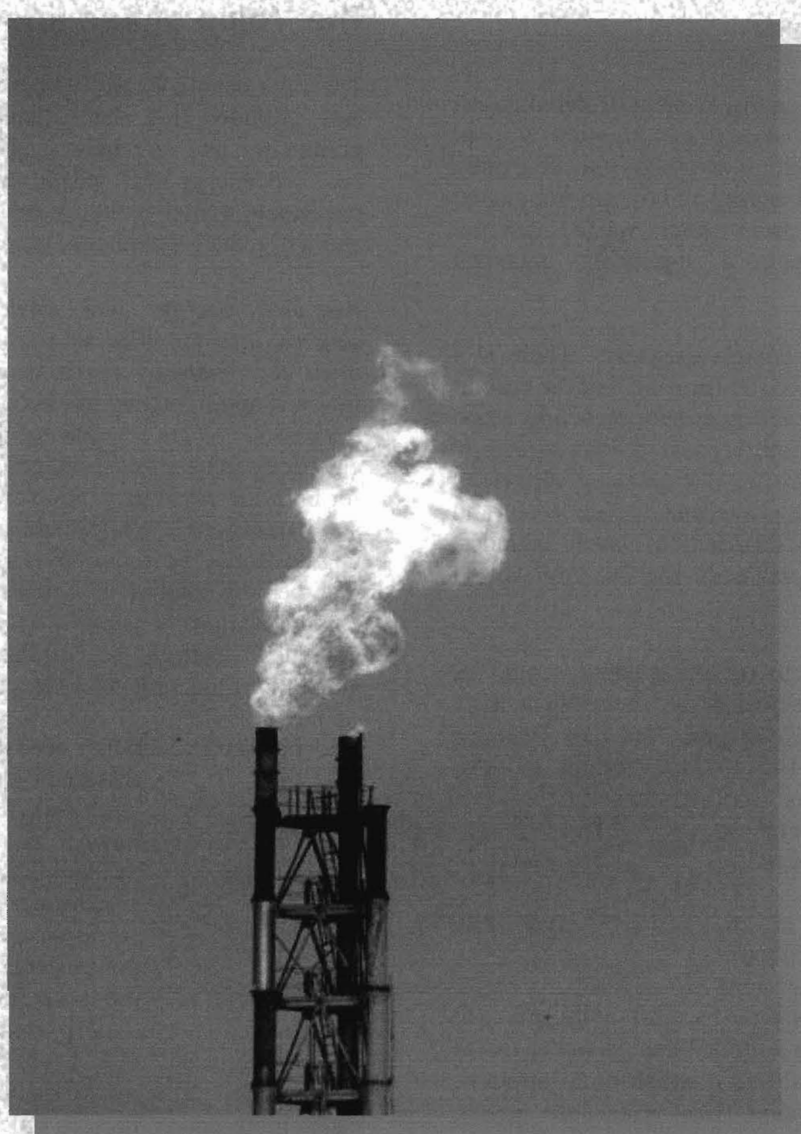

Turbine installation at Northlake

The US, in spite of modest deregulation, remains unintentionally hostile to recycled energy. 15 states retain laws that ban the sale of electricity to anyone but the utility, even if the power is generated on the site of a user. All 50 states ban private wires that cross public roads, thus denying energy innovators any leverage in negotiating the prices their distribution monopoly charges for moving power across the street to the nearest retail customer. Public service commissions regularly approve backup charges that assume 100 percent failure at system peak of all decentralized generation. No commission currently gives DG any credit for avoided T&D capital, avoided line losses or avoided pollution. State and federal environmental rules require new generation to be up to 50 times less polluting than existing generation, while allowing old, inefficient central generation to emit at historic pollution levels. Commissions deny rewards to utilities for efficiency gains.

The bottom line is the US suffers from needlessly inefficient and dirty use of energy. Outmoded regulations prevent energy recycling innovators from picking up US$40-60 billion per year of 'US$20 bills' that are lying on the ground. Policymakers have a golden opportunity; by modernizing the regulations and regulatory approach and removing barriers to efficiency, they can unleash a flood of recycled energy that will pay US industry for its waste energy, reduce dependence on fossil fuel use, cut pollution, and cut future electric prices by 40 percent. Recycled energy is the missing link to sensible energy policy. ■

[1] EPRI, The Electricity Sector Framework for the Future, August 25, 2003, http://www.epri.com/corporate/esff/viewpdf.asp
[2] Casten, T & Collins, M, Cogeneration and On-Site Power Production, Optimizing Future Heat and Power Generation, Nov-Dec 2002
[3] Recycled Energy: An Untapped Resource, Casten and Collins, April 2002. Available at www.primaryenergy.com

Recycled Energy: An Untapped Resource



April 19, 2002

Thomas R. Casten **Martin J. Collins**

Private Power LLC
Recycling Energy

Recycled Energy: An Untapped Resource

Executive Summary

Recycled energy uses the energy content of flared gases, wasted exhaust heat and unused gas pressure drop to generate electricity. Both in terms of the economic value of otherwise wasted energy and the environmental consequences resulting from such wasted energy, recycled energy represents a significant untapped resource.

The benefits of recycled energy are clear. There is a potential to generate between 9% and 13% of the current fossil fueled electrical power by simply recycling waste energy streams. In addition, because the waste energy streams are produced on-site, the recycled electricity would be consumed locally, minimizing line losses and avoiding transmission and distribution system upgrades. And yet, barriers have prevented the development of recycled energy projects.

Overcoming the barriers to recycling energy could be achieved through the inclusion of recycling energy within the scope of the *Renewable Portfolio Standard* (RPS). Senate Energy Bill S. 517 contains an RPS provision that requires US electric providers to purchase credits from a rising percentage of RPS-defined sources. The purposes of the RPS are to reduce our country's dependence on fossil fuel and at the same time reduce the emissions of harmful pollutants and greenhouse gases. Adding recycled energy to the list of RPS-defined sources would accomplish both purposes. Recycled energy production, like renewable power, displaces fossil generation. In addition, recycled energy, by displacing fuel, will significantly reduce emissions of sulfur dioxide, nitrous oxide and carbon dioxide associated with electricity production.

Finally, inclusion of recycled energy within the scope of the RPS will provide needed revenue to our nation's industrial plants. At a time when our nation's various industries are struggling to compete with their respective competitors abroad, the mandated support for recycled energy through the RPS would improve the competitive positions of industrial facilities in world markets.

The US can either build more T&D or encourage decentralized generation.

The Value of Recycled Energy

The clear benefit of recycled energy is that it is fuel-free and pollution-free, and displaces fossil generation, pollutants, and greenhouse gases. In this manner, recycled energy will reduce emissions of NOx, SOx, particulate matter, mercury and hazardous air products and will reduce greenhouse gases.

Recycled energy, like other decentralized energy sources, also provides an alternative to expensive, and often controversial, transmission expansion. The need for such an alternative has become especially clear over the past few years. A spate of recent power failures and electricity generation shortages has pointed to the need for both increased generation and transmission upgrades and expansions. While there is no question that some upgrades may be required, it is a mistake to conclude that the only solution to the existing problems is to build central station generation facilities and transmission upgrades. Instead, decentralized generation offers an alternative, and a relatively less costly one at that.

Decentralized generation needs no new transmission or distribution as it is produced on-site. And while 9% of centrally generated power is lost in transmission, decentralized generation has neither transformer nor line losses because it is also consumed on-site. Even power generated on-site in excess of use will flow to the nearest user, regardless of power sales contract, thereby freeing the T&D system and allowing the existing wires to serve other loads. The overtaxed transmission system will cause more power failures unless 1) more transmission lines are constructed, 2) decentralized generation is built near users, or 3) a combination of both is pursued. Clearly, U.S. policy should encourage the development of more decentralized generation.

Recycled Energy Potential

Potential recycled energy, using only available data, could displace 9% of current US fossil generation. However, such an estimate could reach 13% of fossil-fueled electrical generation by tapping other waste sources not considered or missing data.

Much energy is vented from industrial processes or is lost in the pressure drop of any gas, but little is currently recycled – converted to electricity. The three major sources of recyclable energy are 1) exhaust heat from industrial processes including electric generation, 2) industrial process fugitive tail gas that is flared without energy recovery and 3) gas and steam pressure drop that could provide nearly fuel-free electricity. We list below the identified sources of currently wasted energy. These sources could produce 240,000 to 360,000 gigawatt hours per year of recycled electricity – 9% to 13% of US fossil-fuel based generation.[1]

Exhaust Heat: Exhaust from many industrial processes – steel mills, glass producers, refineries and chemical processes – is vented at 800 to 3,000 degree F. Exhaust from the reciprocating engines and combustion turbines driving gas pipeline compressors is vented at roughly 1,000 degree F. Condensing steam turbine generators can convert 25% of the energy in each of these sources to electricity without burning any added fossil fuel or emitting any added pollution. For installations with low-grade thermal energy needs nearby, the spent steam from backpressure turbine generators can displace boiler fuel and increase recycling to 90% of the exhaust energy.

New electric generation also has energy recycling potential. The US DOE and EPA both have programs to double the percentage of power produced in combined heat and power installations, known as CHP plants, by 2010. By producing steam at higher pressures, these new plants can convert some exhaust energy to electricity at 80% plus efficiency. The extra electricity is essentially fuel-free and pollution-free. This source has not been counted in this analysis.

Industrial Tail Gas: Many industrial processes emit fugitive gas that is flared to reduce hazardous air products. The US EPA aerometric survey identifies 2800 separate point sources of tail gas, with several states not fully reporting.[2] These fugitive gases come from carbon black plants, refineries, chemical factories, automobile and appliance painting operations and ethanol plants. Converting the existing fugitive gas flares to the burners needed for heat recovery will improve combustion and lower stack pollution. Recycled electricity displaces central generation, further lowering pollution. Based on this logic, EPA's MACT guidance for carbon black flare gas states that equipment for recovering heat as described above is a pollution control device.

Recycled tail gas could support 148,000 GWh/year of new fuel-free electrical generation.

Backpressure turbine generator can be used instead to lower gas pressure and produce fuel-free electricity

Gas Pressure Drop: Many processes compress gas or steam to pack more gas or energy into a pipe. Transcontinental natural gas pipelines compress gas to 40 to 110 times atmospheric pressure. Every 50 miles or so, another compressor station boosts the gas pressure for travel to the next station. When the pressurized gas reaches distribution points, pressure is reduced with valves to as low as two times atmospheric pressure. This wastes the energy recovery potential of the pressure drop. Expansion turbine generator sets can lower gas pressure and produce fuel-free electricity.

Similarly, steam systems serving multiple buildings generate steam at ten times atmospheric pressure or higher, to pack more steam in relatively small pipes, and then reduce the pressure at point of use to twice atmospheric pressure with a valve. Backpressure steam turbine generators can convert the pressure drop to fuel-free electricity.

We estimate wasted gas or steam pressure drop could support 78,000 GWh/year of fuel-free generation.

Total Potential for Recycled Energy: Total recycled energy from published data would support 240,000 gigawatt hours per year of fuel-free electrical generation, equivalent in annual output to one third of US nuclear generation in 1999.[3]

State by State Data

The attached table shows the potential for recycled energy by state and the retail value of each state's recycled energy potential. The table limits results to published data and shows the annual kWh per capita of recycled energy potential for each state as well as the current renewable energy production in kWh/capita. Each state and the District of Columbia is ranked from 1 (highest kWh/capita) to 51 for both recycled energy potential and for renewable energy production. Some states with low renewable kWh/capita rankings have high rankings on recycled energy potential. For example, Texas is 44th in renewable but 5th in recycled energy potential. Louisiana is 51st on renewable energy today, but, in spite of under reporting, 23rd on recycled energy.

Recycled energy will be easy to measure, as it will largely come from discreet, non-fueled generators. In some cases, recycling will require a small amount of fossil fuel to stabilize the combustion or to add heat. If that fossil fuel were burned in a conventional electric plant, one third of the energy would be converted to electricity. Thus, an RPS definition of recycled energy should exclude an amount of electricity equal to 33% of the energy content of any incremental fossil fuel burned. The proposed amendment assumes advances in fossil efficiency and deducts 40% supplemental fuel energy content from the RPS definition.

Why Is So Little Energy Recycled Today?

In regulated markets, electrical generation and distribution were natural monopolies and the incumbent utilities had little incentive to capture waste energy. As a result, unintended (and sometimes-intended) barriers were enacted that block the deployment of recycled energy facilities.[4]

Unfortunately, while electricity markets are evolving, many of the barriers to recycling energy remain. Few institutions have been able to develop energy recycling in spite of numerous attempts because of the following regulatory barriers and common practices:

- *Regulated local utilities have little incentive to build recycled energy projects. Fuel savings would simply lower user electricity prices while utility management would have to deal with many small projects.*
- *Producers of tail gas, exhaust heat and pressure drop are not in the energy business and tend to "stick to their knitting," or in current management speak, focus resources on core competencies.*
- *Independent power developers, whose core competency is energy, face high capital costs, high standby and interconnection charges for small recycled energy projects, and then receive discounted prices for the power because the below 50 megawatt blocks do not fit the current power market.*
- *Regulated local utilities, to avoid losing sales and profits, use many techniques to block all decentralized generation.*

Although the societal benefits of recycled energy are clear, few recycled energy projects have been developed. The barriers to recycling energy will continue to impede successful deployment unless certain actions are taken.

Why Recycled Energy Should be Included Within the Scope of the Renewable Portfolio Standard

As explained above, a number of barriers have served to limit the deployment of recycled energy facilities. Nevertheless, the value of such facilities from both an economic and environmental standpoint is clear. A national RPS standard mandating support for recycled energy would serve as an elegant wedge to force modernization of the rules that currently act as barriers to such efficiency. And the inclusion of recycled energy within the scope of the RPS would result in a program that is more cost-effective, more broadly shares the benefits across states, and will be more beneficial for the nation's economic well-being.

Broadening the Scope of the RPS to Include Recycled Energy Should Lower the Overall Cost of the RPS

The RPS in the Senate's recently passed energy bill contains a requirement that all retail electric suppliers purchase credits from eligible renewable facilities, rising to 10% of the supplier's retail sales by 2020. In addition, the RPS language in the Senate bill imposes a credit cap of 3 cents per kilowatt-hour. The rising mandate for credits from renewable sources should force the price of the credit up to the cap as more expensive RPS sources are brought on line. Recycled energy, on the other hand, would be able to overcome its barriers to deployment with credits smaller than the 3 cent cap. In fact, recycled energy facilities could overcome barriers to deployment with a much smaller credit, making recycled energy a very cost-effective RPS source of power that will lower the overall cost of the program.

Including Recycled Energy within the Scope of the RPS Would Result in an RPS that is More National in Scope

The RPS definition currently in the Senate energy bill would primarily benefit certain regions in the country, with ratepayers in other regions of the country paying for that support. If existing renewable generation is taken as an indicator of RPS induced renewables, then states like California, Montana, the Dakotas and Washington will be major beneficiaries, while states like Indiana, Ohio and Texas stand to lose revenue to other states. But these low renewable states have high-recycled energy potential and could satisfy the expanded RPS requirement. Accordingly, adding recycled energy to the RPS definition of eligible sources would extend the benefits of the RPS to many more States. (See page 5 for current renewable energy per capita and state rankings).

Including recycled energy within the Scope of the RPS would Benefit US Industry

Including recycled energy within the scope of the RPS will provide US industrial plants with payment for their presently wasted energy. In addition, recycled electricity generation with exhaust heat and tail gas will produce spent steam that can offset fossil fuel for industrial and institutional thermal needs, further reducing heating costs. Such value from recycled energy would lower costs of production, thereby improving the competitive position of US industries in world markets.

In addition to the benefits to the on-site facility, mandating support for recycled energy will push several technologies up the learning curve, improving their value position. American exports of clean energy products will thus increase.

Including Recycled Energy within the Scope of the RPS Would Educate the Industry on the Benefits of Decentralized Generation

Public education would be an important value of RPS-mandated support for energy recycling. Worldwide production of heat and power is less than optimal. Barriers prevent the optimal deployment of decentralized generation. A national RPS mandate to support renewable and recycled energy will result in the deployment of clean, localized energy generation in every community, at most factories and on many rooftops. The public will learn that decentralized electric power will reduce the need for central station generation facilities or upgraded transmission wires. The RPS mandate will force the industry to recognize the locational value of decentralized energy. It will also give regulators experience with decentralized technologies, providing them with the necessary information to eliminate the barriers to the deployment of such technologies.

Proposed Inclusion of Recycled Energy in RPS Definition

The following amendment would add recycled energy to the RPS definition:

Amend Section 606 of the Senate energy bill by adding ", recycled energy" after "generation offset," in subsection (l)(3) and subsection (l)(10) and by adding the following after subsection (l)(13):

"(14) RECYCLED **ENERGY**. The term 'recycled energy' means (1) exhaust heat resulting from any industrial process; (2) industrial tail gas that would otherwise be flared, incinerated, or vented; or (3) energy extracted from a pressure drop in any gas, excluding any pressure drop from a condenser that subsequently vents the resulting heat. If the process used to recycle energy incorporates supplemental use of a fossil fuel, the amount of the recycled energy that qualifies as a renewable eligible resource shall be reduced by 40% of the net heating value of the incremental fossil fuel used in the process."

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[1]Internal analysis of Private Power based on US EPA data cited below, individual industry data and pipeline compressor databases.

[2]US EPA Envirofacts database, July 2001. http://www.epa.gov/enrivo/index_java.html

[3]Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and Form EIA-900, "Monthly Nonutility Power Plant Report, and Form EIA-860B, "Annual Electric Generator Report – Nonutility".

[4]See chapter 8, Barriers to Efficiency, in "Turning Off The Heat," by Thomas R. Casten, Prometheus Press, 1998.

	Potential Recycled Generation - GWh/yr				Potential Recycled Generation Benefits				Existing Renewable Generation (1999)		
	Pipeline Compressor Station Heat	Flared Tail & Stack Gas	Steam and Gas pressure Drop	Total Recycled Potential	Recycled Energy as % of Fossil Fuel Generation	Retail Value of Recycled Energy (millions)	Potential Recycled kWh per Capita / yr	*State Ranking per Capita*	Existing Renewable Generation (Gwh)	Renewable kWh per Capita / yr	*State Ranking per Capita*
Alabama	438	4,362	1119	5,907	8%	331	1,328	*11*	11,673	2625	*9*
Alaska	0	104	887	984	20%	98	1,569	*6*	817	1303	*18*
Arizona	540	949	655	2,132	5%	153	416	*40*	9,863	1922	*14*
Arkansas	308	1,894	805	3,002	10%	174	1,123	*15*	4,008	1499	*15*
California	284	5,167	6019	11,347	12%	965	335	*49*	65,454	1932	*13*
Colorado	159	2,750	1206	4,103	11%	246	954	*19*	1,594	371	*37*
Connecticut	34	3,776	1009	4,813	35%	457	1,413	*10*	2,583	758	*22*
D. of Columbia	0	152	296	445	193%	33	778	*27*	0	0	*49*
Delaware	0	1,015	187	1,200	17%	82	1,531	*8*	0	0	*50*
Florida	140	3,068	1275	4,459	3%	308	279	*50*	5,683	356	*39*
Georgia	164	5,811	1399	7,353	9%	456	898	*24*	5,795	708	*24*
Hawaii	0	366	61	427	4%	60	353	*46*	910	751	*23*
Idaho	193	295	350	834	213%	35	645	*30*	13,930	10765	*4*
Illinois	602	6,189	3917	10,641	13%	702	857	*25*	1,312	106	*45*
Indiana	472	11,212	2063	13,717	11%	700	2,256	*4*	530	87	*47*
Iowa	352	810	1120	2,269	7%	134	775	*28*	1,363	466	*34*
Kansas	1,012	1,075	919	2,992	9%	188	1,113	*16*	12	5	*48*
Kentucky	708	8,028	1008	9,731	11%	399	2,408	*3*	2,569	636	*26*
Louisiana	1,667	150	2293	4,062	6%	268	909	*23*	0	0	*51*
Maine	14	1,103	429	1,546	29%	153	1,212	*12*	6,834	5360	*6*
Maryland	48	0	1250	1,283	4%	86	242	*51*	1,965	371	*36*
Massachusetts	19	745	1767	2,509	7%	238	395	*43*	3,066	483	*33*
Michigan	443	5,064	3715	9,165	11%	651	922	*22*	4,283	431	*35*
Minnesota	540	90	1764	2,369	7%	137	482	*39*	2,953	600	*28*
Mississippi	1,200	808	628	2,625	10%	155	923	*21*	1,456	512	*31*
Missouri	222	669	1359	2,228	4%	134	398	*42*	1,914	342	*40*
Montana	130	2,097	266	2,490	14%	124	2,760	*2*	13,874	15378	*2*
Nebraska	130	184	551	857	5%	45	501	*35*	1,731	1011	*19*
Nevada	67	163	484	704	2%	43	353	*47*	4,253	2128	*11*
New Hampshire	0	422	291	712	14%	83	576	*32*	2,554	2067	*12*
New Jersey	82	103	3308	3,449	13%	314	410	*41*	1,409	167	*41*
New Mexico	564	19	562	1,137	4%	75	625	*31*	254	139	*42*
New York	217	1,620	8212	9,956	12%	1,115	525	*34*	27,476	1448	*17*
North Carolina	145	3,122	1204	4,456	6%	290	554	*33*	5,262	654	*25*
North Dakota	265	150	334	746	3%	41	1,162	*14*	2,615	4072	*7*
Ohio	352	5,136	3854	9,283	7%	603	818	*26*	1,060	93	*46*
Oklahoma	241	4,040	1059	5,320	10%	319	1,542	*7*	3,344	969	*20*
Oregon	173	1,555	712	2,429	23%	117	710	*29*	46,177	13497	*3*
Pennsylvania	949	10,060	3539	14,503	12%	957	1,181	*13*	4,515	368	*38*
Rhode Island	19	14	346	374	6%	38	357	*45*	120	115	*43*
South Carolina	53	725	755	1,524	4%	84	380	*44*	3,235	806	*21*
South Dakota	96	73	206	373	10%	23	494	*36*	6,677	8846	*5*
Tennessee	703	3,834	1238	5,759	10%	322	1,012	*17*	8,458	1487	*16*
Texas	1,310	35,424	7149	43,747	14%	2,844	2,098	*5*	2,219	106	*44*
Utah	63	0	714	767	2%	37	343	*48*	1,419	635	*27*
Vermont	0	154	144	297	690%	30	488	*38*	1,607	2639	*8*
Virginia	198	5,255	1628	7,062	16%	424	998	*18*	3,474	491	*32*
Washington	212	1,544	1159	2,898	23%	130	492	*37*	98,336	16684	*1*
West Virginia	304	1,750	648	2,696	3%	137	1,491	*9*	930	514	*30*
Wisconsin	82	3,154	1870	5,078	12%	289	947	*20*	3,129	583	*29*
Wyoming	251	1,575	334	2,156	5%	95	4,366	*1*	1,181	2393	*10*
U.S. Total	16,164	147,827	78,069	240,914	9.3%	15,924	856		395,874	1407	

States that under / do not report are in red

Note: Exhaust heat from steel and glass furnaces and other industrial processes could support 35,000 to 70,000 more GWh of annual fuel-free generation, but have been omitted due to lack of state data.

	Emissions from Fossil Fuel-based Electricity Production - 1999 (thousand metric tonnes)			Potential to Reduce Emissions w/ Recycled Energy (thousand metric tonnes)			
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	% Reduction
Alabama	435	230	70,181	36	19	5822	8%
Alaska	5	21	4,766	1	4	1023	21%
Arizona	58	119	39,111	3	6	2089	5%
Arkansas	64	85	27,326	7	10	3065	11%
California	0	26	19,057	0	3	2479	13%
Colorado	78	122	33,493	9	14	3949	12%
Connecticut	21	5	4,872	8	2	1883	39%
D. of Columbia	1	0	235	2	0	495	211%
Delaware	24	11	4,825	5	2	918	19%
Florida	585	289	103,856	19	10	3413	3%
Georgia	437	191	70,128	44	19	6987	10%
Hawaii	15	8	5,304	1	0	258	5%
Idaho	0	0	5	0	0	11	233%
Illinois	559	307	73,002	80	44	10507	14%
Indiana	736	422	111,323	91	52	13748	12%
Iowa	131	138	33,165	10	10	2423	7%
Kansas	81	124	33,017	8	12	3273	10%
Kentucky	722	305	86,740	85	36	10161	12%
Louisiana	116	116	39,385	7	7	2426	6%
Maine	5	1	770	1	0	242	31%
Maryland	278	80	30,632	11	3	1184	4%
Massachusetts	103	37	20,049	8	3	1592	8%
Michigan	364	255	68,666	43	30	8032	12%
Minnesota	77	113	29,988	6	9	2395	8%
Mississippi	99	64	20,304	11	7	2323	11%
Missouri	225	258	62,940	9	10	2409	4%
Montana	15	54	16,970	2	8	2615	15%
Nebraska	53	83	18,535	3	4	948	5%
Nevada	45	65	20,782	1	2	559	3%
New Hampshire	44	8	4,388	7	1	684	16%
New Jersey	44	27	8,485	6	4	1192	14%
New Mexico	51	114	29,140	2	4	1117	4%
New York	146	50	30,675	20	7	4100	13%
North Carolina	389	161	61,695	25	11	4021	7%
North Dakota	138	104	31,266	4	3	883	3%
Ohio	1,111	425	114,933	90	34	9318	8%
Oklahoma	83	135	40,887	9	15	4579	11%
Oregon	13	18	4,889	3	5	1229	25%
Pennsylvania	786	205	84,141	103	27	11072	13%
Rhode Island	0	0	8	0	0	1	6%
South Carolina	225	85	32,563	10	4	1451	4%
South Dakota	21	17	3,816	2	2	399	10%
Tennessee	354	151	50,366	38	16	5426	11%
Texas	468	551	201,235	70	82	30007	15%
Utah	25	93	31,453	1	2	743	2%
Vermont	0	0	39	0	0	294	752%
Virginia	194	85	32,823	34	15	5792	18%
Washington	66	40	8,933	16	10	2218	25%
West Virginia	1,113	262	82,772	35	8	2591	3%
Wisconsin	179	169	41,102	23	21	5193	13%
Wyoming	77	166	43,152	4	9	2393	6%
U.S. Total	10,857	6,396	1,988,190	1013	609	191,933	10%

Private Power LLC

Recycling Energy

[redacted]

Private Power recycles normally wasted energy into heat and power to achieve double bottom line benefits – lower energy costs and lower pollution.

To accomplish this mission, the company develops, manufacturers and owns combined heat and power (CHP) plants that convert normally wasted exhaust heat to power and thermal energy. We extract both heat and power from streams of currently wasted tail gas, exhaust and pressure drop in industrial and institutional processes.

1. We provide the capital and knowledge to generate heat and power on site.
2. We align our interests with customer interests through gain sharing.
   - *We provide heat and power under long-term contracts, freeing customer capital for core activities.*
   - *We meter extensively.*
   - *We help customers lower energy use per unit of production by over 20%.*
3. We demand each project have both cost and pollution benefits, constantly staying ahead of pollution limitations and earning pollution credits.
4. We are a knowledge based company, relying on the deep and varied experience of our managers to achieve double bottom line results.

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Clean Energy Technologies

A Preliminary Inventory of the Potential for Electricity Generation

A Report to

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Washington, DC

by

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1. Introduction & Results

The Nation's power system is facing a diverse and broad set of challenges. These range from a restructuring and increased competitiveness in power production to the need for additional production and distribution capacity to meet potential demand growth, increased quality and reliability of power and power supply. In addition, there are growing concerns about emissions from fossil-fuel powered generation units and voluntary reductions in CO_2 emission intensity of power generation.

Although these challenges may create uncertainty within the financial and electricity supply markets, they also offer the potential to explore new opportunities to support the accelerated deployment of cleaner and most cost-effective technologies to meet such challenges. The Federal Government and various state governments, for example, support the development of a sustainable electricity infrastructure. As part of this policy, there are a variety of programs to support the development of "cleaner" technologies such as combined heat and power (CHP, or cogeneration) and renewable energy technologies. Besides these two obvious technology areas, there are many more opportunities for the development of "cleaner" energy technologies, including waste to energy technologies, industrial gasification technologies to increase energy recovery, as well as less traditional CHP technologies.

This report is a preliminary study of the potential contribution of this "new" generation of clean energy supply technologies to the power supply in the United States. For each of the technologies the report provides a short technical description, as well as an estimate of the potential for application in the U.S., estimated investment and operation costs, as well as impact on air pollutant emission reductions. The report summarizes the potential magnitude of the benefits of these new technologies. The report does not yet provide a robust cost-benefit analysis. It is stressed that the report provides a preliminary assessment to help focus future efforts by the federal government to further investigate the opportunities offered by new clean power generation technologies, as well as initiate policies to support further development and uptake of clean power generation technologies.

The preliminary study was funded by the U.S. Environmental Protection Agency's Office of Atmospheric Programs to evaluate the opportunities offered by less traditional new clean power technologies. The specific intent is to determine whether these "less traditional" technologies have sufficient market potential to warrant the development of what might be termed a "clean energy technology initiative," or a new clean energy supply-side initiative that might complement the many energy efficiency programs now offered on the demand side.

The study identified 19 diverse technologies. The technologies vary from small distributed power systems on farms to large integrated gasifiers at petroleum refineries. The characteristics of the technologies and potential users vary widely. Hence, the technologies may face very different barriers and opportunities for implementation.

The preliminary results indicate that there is a technical potential of nearly 100,000 megawatts (MW) of untapped electrical capacity. This electrical capacity is capable of producing 742 terawatt-hours (TWh) of electricity, saving an estimated 19 percent of current U.S. electricity consumption. The resulting energy savings from this alternative electricity generation, about 7.4 quadrillion Btus (Quads) of primary energy, are anticipated to reduce carbon dioxide emissions (CO_2) by nearly 400 million metric tons along with 740,000 tons of nitrogen oxides (NOx) over 2 million tons of sulfur dioxide (SO_2), and 10 tons of mercury (Hg) emissions.

Table 1 below is a summary of the technical potential for electricity generation for each technology. The potential in terms of capacity (MW), electricity production (TWh/year), and primary energy savings (trillion Btus, or TBtu) are given. These technologies generate electricity from energy sources that would otherwise be dissipated to the environment or abated at an environmental and financial cost. Hence the electricity generated avoids the emissions production from grid electricity. These avoided emissions are presented in Table 1.

Table 1. Summary of Clean Energy Technologies Potential

Further research to confirm the potential energy savings and to provide a credible cost-benefit analysis are recommended to improve the estimates and to select the most promising opportunities. For example, a number of the technologies also provide thermal benefits in the form of steam or heat in addition to the electricity generation. Including these and other benefits in the assessment would undoubtedly improve the assessment of cost-effectiveness as well as drive additional environmental benefits. Also, as the technologies have very different characteristics and potential barriers to implementation, further research is recommended to better characterize and evaluate opportunities for an effective and efficient policy to support further development and uptake of the clean power technologies identified in the report.

2. District Heating – Back-Pressure Power Recovery

District Heating is an established, mature technology, with several large steam systems having been installed in the latter half of the nineteenth century. The principle of district heat systems is that a central plant produces steam or high-pressure hot water for distribution to commercial and large residential customers. As a result of lower capital and energy costs, modern district heating systems use high-pressure hot water almost exclusively. Older systems continue to use steam, and are largely locked into this distribution method because hot water systems require a new set of distribution pipes, and cannot run the existing steam powered absorption chillers. A typical steam based system starts with some form of cogeneration of steam and electricity, with the resulting steam at 120 to 150 pounds per square inch (psig). This steam then flows through the distribution system to locations up to 3 miles away. When the steam enters the building, the pressure is reduced to 10-15 psig to minimize the stresses on the building's internal system. Once the heat has been extracted, the condensate is returned to the steam generating plant. Typically, the pressure reduction at the building is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop between 150 and 15 psig. This energy could be recovered by using a micro scale back-pressure steam turbine. Several manufactures produce these turbine sets, such as Turbosteam (previously owned by Trigen) and Dresser-Rand (see Table 2 for a summary).

Table 2. Steam Micro Turbine Characteristics

Turbine Name	Capital Cost	Maintenance Cost[a]	Energy Flow	Power Out	Conversion Efficiency[b]
	($/kW)	($/kW)	(MBtu/h)	(kW)	(%)
Trigen BP-50	660	60	3.2	50	46%
Trigen BP-100	540	30	6.3	100	47%
Trigen BP-150	440	20	9.6	150	47%

Source: Trigen Energy, 2000b; Michaels, 2000

a. Based on a maintenance cost of $3000/yr (Trigen Energy, 2000b)

b. The efficiency with which the turbine converts enthalpy loss to electric power.

Developing a high quality characterization of all existing district steam systems in the US would require a significant effort. The Energy Information Administration (EIA) of the US Department of Energy undertook one detailed survey in 1993. The 1998 Commercial Buildings Energy Consumption Survey (CBECS) (EIA, 1998), found district heat consumption by all commercial buildings to be 533 TBtu (109,000 buildings and 5,606 million square feet). The majority of this consumption was by buildings in climate zones of 4,000 to 7,000 heating degree-days. Within the group, the largest estimated consumers of district heat included colleges and universities, hospitals, and industrial buildings.

Based on the two EIA surveys, the data suggest that annual district heat production in the U.S. is roughly 500 TBtu, the majority of which (90%) is steam-based systems. The share of district heat applicable for the installation of micro-turbine technology is estimated at 30% (due to heat load variation and location limitations), and the losses due to flow control are estimated at 10%. Based on these assumptions and a turbine efficiency of 46% we estimate the total potential in district heating systems at 1.5 to 1.6 TWh.

Technical potential:	290 MW
Running time:	5500 hours/year
Investment costs:	600 \$/kWe
Operation costs:	0.011 \$/kWh

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3. Industry – Back-Pressure Power Recovery

Industry consumed at least 3,635 TBtu of fuels in 1998 to generate steam. The steam is generated at high pressures, but often the pressure is reduced to allow the steam to be used by different processes. For example, steam is generated at 120 to 150 psig. This steam then flows through the distribution system within the plant. The pressure is reduced to as low as 10-15 psig for use in different process. Once the heat has been extracted, the condensate is often returned to the steam generating plant. Typically, the pressure reduction is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop. This energy could be recovered by using a micro scale back-pressure steam turbine. Several manufactures produce these turbine sets, such as Turbosteam (previously owned by Trigen) and Dresser-Rand (see Table 3 for a summary).

Table 3. Steam Micro Turbine Characteristics

Turbine Name	**Capital Cost**	**Maintenance Cost**[a]	**Energy Flow**	**Power Out**	**Conversion Efficiency**[b]
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BP-100	540	30	6.3	100	47%
BP-150	440	20	9.6	150	47%

Source: Trigen Energy 2000b; Michaels, 2000

c. Based on a maintenance cost of $3000/yr (Trigen Energy, 2000b)

d. The efficiency with which the turbine converts enthalpy loss to electric power.

e. Electricity output over total energy into the turbine (including energy that goes on to heat the building). As a result, this efficiency does not reflect losses in steam generation or distribution.

The potential for application in industry is difficult to estimate as no data is collected on the use of steam (e.g. pressure) in industrial facilities. Applications of this technology have been commercially demonstrated for campus facilities (included in a separate technology description), pulp & paper, food, and lumber industries. Based on industries that typically use low-pressure process steam, the technical potential for application of this technology is estimated at 40% of total steam demand in industry (Einstein et al., 2001). We estimate that 1450 TBtu fuel is used to generate 1190 TBtu steam (82% efficiency, HHV), of which about 110 TBtu is already generated through cogeneration (based on MECS 1998 data).

Based on the production of 13.5 kWh/MBtu steam (Casten and O'Brien, 2003), and the above steam production, the technical potential for power generation is estimated at 14.7 TWh, using an additional 94 TBtu of fuel to make up for enthalpy losses in the steam.

The actual power generation on a site will vary depending on steam pressures for steam generation and actual use in the process. It is hard to make a more accurate estimate without further data on steam pressures in industrial steam systems.

Technical potential: 2100 MW

Running time:	7000 hours/year (mix of two-shift plants and continuous operations)
Investment costs:	600 $/kWe
Operation costs:	0.011 $/kWh

References

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4. Natural gas Pressure Recovery Turbines

In 1999, the U.S. consumed roughly 610 Bm^3 (22 Tcf) of natural gas (EIA, 2000). The transport of natural gas in the U.S. accounts for roughly 3.4% of U.S. natural gas consumption. While it is necessary to transport natural gas at high pressures, end-users require gas delivery at only a fraction of main pipeline pressure. Pressure is generally reduced with a regulator, a valve that controls outlet pressure. Expansion turbines can replace regulators. These turbines offer a way to capture some of the energy contained in high-pressure gas by harnessing the energy released as gas expands to low pressure, thus generating electricity. Expansion turbines use the pressure drop when natural gas from high-pressure pipelines is decompressed for local networks to generate power. Expansion turbines (also known as generator loaded expanders) actually serve as a form of power recovery, utilizing otherwise unused pressure in the natural gas grid. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. The drop in pressure in the expansion cycle causes a drop in temperature. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below –15°C. In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. Expansion necessitates heating the gas just before or after expansion. The heating is generally performed with either a combined heat and power (CHP) unit, or a nearby source of waste heat. We focus on locations with sufficient low-temperature waste heat available to preheat the gas, such as power stations and industrial sites. These are also the sites where most natural gas is used. Modern expansion turbines are found at various sites in Europe and Japan.

Lehman and Worrell (2001) studied the potential in the U.S. and found that expansion turbines have the potential to generate a theoretical maximum of 21 TWh in industrial and utility settings, recovering 11% of natural gas transport energy as electricity.

Technical potential: 3.8 GW

Running time: 5500 hours/year

Investment costs: $1300/kWe

Operation costs: 0.009 $/kWh

References

Energy Information Administration, 2000. "Natural Gas Annual 1999," Energy Information Administration, Washington, D.C.

Lehman B. and E. Worrell. 2001. "Electricity Production from Natural Gas Pressure Recovery Using Expansion Turbines," *Proc. 2001 ACEEE Summer Study on Energy Efficiency in Industry – Volume 2*, Tarrytown, NY, July 24-27th, 2001, pp. 43-54.

5. Pressure Power Recovery

Various processes run at elevated pressures, enabling the opportunity for power recovery from the pressure in the flue gas. The major current application for power recovery in the petroleum refining industry is the Fluid Catalytic Cracker (FCC). However, power recovery can also be applied to hydrocrackers (petroleum refining), dual-pressure nitric acid plants (chemical industry) and pressurized blast furnaces (iron and steel industry).

Refining. Power recovery applications for FCC are characterized by high volumes of high temperature gases at relatively low pressures, while operating continuously over long periods of time between maintenance stops (> 32,000 hours). The turbine is used to drive the FCC compressor or for to generate (additional) power (Worrell and Galitsky, 2004). There is wide and long-term experience with power recovery turbines for FCC applications. Various designs are marketed, and newer designs tend to be more efficient in power recovery. Many refineries in the US and around the world have installed recovery turbines. Valero has recently upgraded the turbo expanders at its Houston and Corpus Christi (Texas) and Wilmington (California) refineries. Valero's Houston Refinery replaced an older power recovery turbine to enable increased blower capacity to allow an expansion of the FCC. At the Houston refinery the rerating of the FCC power recovery train led to power savings of 22 MW (Valero, 2003), and will export additional power (up to 4 MW) to the grid.

Power recovery turbines can also be applied at hydrocrackers. Power can be recovered from the pressure difference between the reactor and fractionation stages of the process. In 1993 the Total refinery in Vlissingen, The Netherlands, installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker (45,653 b/calendar day). The cracker operates at 160 bar. The power recovery turbine produces about 7.3 GWh/year.

Based on the installation at Valero we estimate the total potential for power export in all U.S. refineries at 170 MW. Our analysis indicates that 50% of the potential FCC capacity can install power recovery turbines cost-effectively. This will produce 722 GWh of power annually (8500 hours/year). Based on the installed hydrocracker capacity of 1.47 million barrels/day, we estimate the additional potential for power recovery for hydrocrackers at 29 MW, producing 247 GWh/year.

Chemicals. Nitric acid is produced through the controlled combustion of ammonia. The modern process variant is the dual-pressure process, allowing power recovery between the two reactors. Also, the single-stage high-pressure process allows for power recovery. The recovered power can be used to power the compressors or for power generation. The U.S. chemical industry produces about 7 million tons of nitric acid per year at multiple locations. Expanders can also be used in the production of ethylene oxide. The expanders are often used to drive the compressor. Hence, we assume that no additional power is generated, although the expander may reduce the need for a steam turbine or electrically driven compressor, potentially reducing electricity use onsite of the chemical plant.

Iron & Steel. Top pressure recovery turbines are used to recover the pressure in the blast furnace.[1] Although the pressure difference is low, the large gas volumes make the recovery economically feasible. The pressure difference is used to produce 15-40 kWh/t hot metal (Stelco, 1993). Turbines are installed at blast furnaces worldwide, especially in areas where electricity prices are relatively high (e.g. Western Europe, Japan). The standard turbine has a wet gas cleanup system. The top gas pressure in the U.S. is generally too low for economic power recovery. A few large blast furnaces (representing about 11 Mt of production) have sufficiently high pressure (Worrell et al., 1999). We estimate the technical potential at 325 GWh, or about 40 MW capacity.

Technical potential:	239 MW
Running time:	8500 hours/year
Investment costs:	1500 $/kWe (estimate)
Operation costs:	0.01 $/kWh (estimate)

References

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Worrell, E. and C. Galitsky. 2004. Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR® Guide for Energy and Plant Managers. Berkeley, CA: Lawrence Berkeley National Laboratory.

[1] Top pressure recovery turbines (dry type) use a dry gas clean up system that raises the turbine inlet temperature, increasing the power recovery by about 25-30% (Stelco, 1993). However, the system is more expensive, estimated at 28 US$/t hot metal. Due to the high costs, we assume that this system will not be implemented on existing blast furnaces in the U.S. in the near term.

6. Organic Rankine Cycle

Organic Rankine Cycle (ORC) is the same process as a steam turbine system with the driving fluid being an organic fluid instead of steam. The standard Rankine Cycle requires superheated steam above 600°C. ORC can work with lower temperature fluids in the range of 100°C to 400°C. Lower temperature operation allows lower quality heat, often residual heat that would otherwise be wasted, to be used to generate electricity. The efficiency is around 10-20% depending on the temperature of the fluid. Fluids used in ORC are CFCs, Freon, isopentane and ammonia. The range for heat recovery capacities of ORC turbines is 400 to 1500 kW. A proposed large ORC project in The Netherlands had a simple payback of 6.5 years and capital costs of about $950 per kW (800 Euros per kWe).

One estimate of current EU market adoption of ORC is 2 – 5 MWe with an expected market potential of 500 MW in 2010 in the EU (12). A study in Germany estimated the technical potential of ORC at approximately 500 MWe in German refineries, chemical, iron and steel, non-metallic minerals industries. Based on fuel use by these industries in Europe (EU-12), Germany and the U.S. we estimate the technical potential at 3000 MW. Based on a penetration rate of 25%, the total potential in the U.S. is estimated at 750 MW.

Technical potential:	750 MW
Running time:	6500 Hours/year
Investment costs:	$950/kWe
Operation costs:	0.01 $/kWh (estimate)

References

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7. Flare Gas Recovery

In oil and gas production methane-containing gases are vented and flared throughout the production cycle. In natural gas production methane is vented and leaking from storage facilities and pipelines. In oil production, methane is vented from oil tanks and may leak from refineries. Furthermore, oil refineries flare methane and hydrocarbon containing gases. Flares are used for both background and upset (emergency) use. In all cases the methane can be recovered and used for local power production. The recovery and use for power generation will not only offset power generation but also reduce methane emissions, a potent greenhouse gas, leading to double benefits. Companies like BP have shown that it is possible to reduce the leaks and recover methane from oil and gas production facilities at a profit.

The US EPA estimates total methane emissions at 100,048 Million ft^3 from natural gas systems and 2,885 Million ft^3 from refineries in 2000 (EPA, 2002). Using a lower heating value (LHV) of 1050 kilojoules (kJ)/cubic foot (ft^3), this would give a total CH_4-energy content of 102 TBtu. Methane emissions from natural gas systems are due to leakage from storage and in pipelines. Emissions from oil systems are mainly vents from oil tanks. For this analysis we assume that 25% of the emissions are recoverable for power generation. Furthermore, we assume that the gas is combusted in micro-turbines with an efficiency of 28% (LHV).

Flare gas recovery (or zero flaring) is a strategy evolving from the need to improve environmental performance. Generally, conventional flaring practice has been to operate at some flow greater than the manufacturer's minimum flow rate to avoid damage to the flare (Miles, 2001). Typically, flared gas consists of background flaring (including planned intermittent and planned continuous flaring) and upset-blowdown flaring. In offshore flaring, background flaring can be as much as 50% of all flared gases (Miles, 2001). In refineries, background flaring will generally be less than 50%, depending on practices in the individual refinery. Reduction of flaring can be achieved by improved recovery systems, including installing recovery compressors. This technology is commercially available. For example, an Arkansas refinery recently installed a new flare gas recovery system to reduce emissions. New compressors and liquid-seals have been installed, and the two flare gas recovery systems have reduced flaring to near-zero levels (Fisher and Brennan, 2002). A plant-wide assessment of the Equilon refinery in Martinez (now fully owned by Shell) highlighted the potential for flare gas recovery. The refinery will install new recovery compressors to reduce flaring.

Flared gas contains on average 25% methane and 35% VOCs. Standard engineering assessments suggest nearly all is combustible. Based on typical emissions of ChevronTexaco refinery in Richmond, CA total amount of HC flared is 0.0038 kg HC/bbl-processed. Based on national input of 5,514 Million bbl, the total amount of combustibles in flared gas is estimated at 20.9 kton. For ease of calculation we assume an average heating value of 41.9 GJ/ton. Hence total amount of recoverable fuels would be 0.83 TBtu (878 TJ) (2000). Refinery flare gas is combusted in a standard industrial cogeneration unit with an efficiency of 36% (LHV).

Technical potential:	260 MW
Running time:	8500 hours/year (98% availability)
Investment costs:	1400 $/kWe
Operation costs:	0.015 $/kWh

References

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8. Advanced Cogeneration – Iron & Steel Industry

All plants and sites that need electricity and heat (i.e. steam) in the steel industry are excellent candidates for cogeneration. Conventional cogeneration uses a steam boiler and steam turbine (back pressure turbine) to generate electricity. Steam systems generally have a low efficiency and high investment costs. Current steam turbine systems use the waste fuels, e.g. at Inland Steel and US Steel Gary Works. Modern cogeneration units are gas turbine based, using either a simple cycle system (gas turbine with waste heat recovery boiler), or a combined cycle integrating a gas turbine with a steam cycle for larger systems.

Integrated steel plants produce significant levels of off-gases (coke oven gas, blast furnace gas, and basic oxygen furnace-gas). Specially adapted turbines can burn these low calorific value gases at electrical generation efficiencies of 45% (LHV) but internal compressor loads reduce these efficiencies to 33% (Mitsubishi, 1993). Mitsubishi Heavy Industries has developed such a turbine and it is now used in several integrated steel plants around the world, e.g. Kawasaki Chiba Works (Japan) (Takano et al., 1989) and Corus (IJmuiden, The Netherlands) (Anon., 1997c). These systems have low NOx emissions (20 ppm) (Mitsubishi, 1993).

Our research indicates that steel production facilities have ready access to coke oven gas (55% of integrated plants in the U.S.) and can repower their generating systems with a combination off-gas turbine/steam turbine system. Currently, almost 7 TWh of electricity is generated by the iron and steel industry, of which 72% by steam turbines (AISI, 1997; EIA, 1997). Use of combined cycles would result in an increase in electricity generation of 3.0 TWh. Investments for the turbine systems are $1090/kWe (Anon.,1997c).

Technical potential:	355 MW
Running time:	8500 hours/year
Investment costs:	1090 $/kWe
Operation costs:	0.004$/kWh

References

American Iron and Steel Institute, 1997. *1996 Annual Statistical Report*, Washington, DC: AISI.

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Takano, H., Kitauchi, Y., and Hiura, H., 1989. Design for the 145 MW Blast Furnace Gas Firing Gas Turbine Combined Cycle Plant," *Journal of Engineering for Gas Turbines and Power*, **111** (April): 218-224.

9. Cheng Cycle or Steam Injected Gas Turbine

This type of turbine uses the exhaust heat from a combustion turbine to turn water into high pressure steam. This steam is then fed back into the combustion chamber to mix with the combustion gas. This technology is also known as a steam injected gas turbine (STIG). The advantages of this system are (Willis and Scott 2000):

- Added mass flow of steam through turbine increases power by about 33%.
- Simplifies the machinery involved by eliminating the additional turbine and equipment used in combined cycle gas turbine.
- Steam is cool compared to combustion gasses helping to cool the turbine interior.
- Reaches full output more quickly than combined-cycle unit (30 minutes verses 120 minutes).
- Applicable for DER applications due to smaller equipment size.

Additional advantages are that the amounts of power and thermal energy produced by a turbine can be adjusted to meet current power and thermal energy (steam) loads. If steam loads are reduced then the steam can be used for power generation, increasing output and efficiency (Ganapathy 2003).

Drawbacks include the additional complexity of the turbine's design. Additional attention to the details of the turbine's design and materials are needed during the design phase. This may result in a higher capital cost for the turbine compared to traditional models.

Combined cycles (combining a gas turbine and a back-pressure steam turbine) offer flexibility for power and steam production at larger sites, and potentially at smaller sites as well. STIG can absorb excess steam, e.g. due to seasonal reduced heating needs, to boost power production by injecting the steam in the turbine. The size of typical STIGs starts around 5 MWe. STIGs are found in various industries and applications, especially in Japan and Europe, as well as in the U.S. International Power Technology (CA), for example, installed STIGs at Sunkist Growers in Ontario (CA) in 1985.

According to the Onsite Sycom study of 2000, the total remaining potential for "normal" cogeneration in sectors with large variations in steam demand is roughly 31,000 MW in industry, and 8690 MW in large commercial buildings (over 5 MWe) (Onsite 2000, Onsite 2000b). Our research suggests that perhaps 50% of the sites can have a STIG. For this analysis, we further assume that 50% of the time the unit can operate in STIG mode (i.e. steam is not used for other purposes).

A STIG produces about 25-33% extra power than a standard turbine. In the calculations we assume 25% additional power generation for a STIG. The net additional power generation (compared to a standard CHP unit) for STIGs is estimated at 1938 MW for industry and 543 MW for commercial buildings (on top of the CHP potential with traditional CHP units). The total technical potential of STIG-based CHP is provided below.

Technical potential:	7750 MW for industry 2172 MW for commercial buildings	
Running time:	Industry Commercial buildings	8500 hrs/yr. 4000 hrs/yr.

Investment costs: $1000 per kW (Goldstein et al. 2003)

Operation costs: $0.006 per kWh (Goldstein et al. 2003)

References

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10. Gasturbine Process heater

Modern turbine designs allow higher inlet and outlet temperatures. The makes it possible to use the flue gas of the turbine to heat a reactor in the chemical and petroleum refining industries. One option is the so-called *"re-powering"* option. In this option, the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen, and can thus be used as combustion air for the furnaces. The gas turbine can deliver up to 20% of the furnace heat. The re-powering option is used by a few plants around the world. Another option, with a larger CHP potential and associated energy savings, is *"high-temperature CHP."* In this case, the flue gases of a CHP plant are used to heat the input of a furnace. Zollar (2002) discusses various applications in the chemical and refinery industries. The study found a total potential of 44 GW. The major candidate processes are atmospheric distillation, coking and hydrotreating in petroleum refineries and ethylene and ammonia manufacture in the chemical industry. The simple payback period is estimated at 3 to 5 years, depending on the electricity costs. The additional investments compared to a traditional furnace were estimated at 630 $/kW (1997) (Worrell et al., 1997; Onsite, 2000). Excessive costs for adaptation of an existing furnace are additional to the given investment costs.

Technical potential:	44,000 MW
Running time:	8300 hours/year (95% availability)
Investment costs:	$630/kWe
Operation costs:	$0.004/kWh

References

Onsite Sycom. 2000. The Market and Technical Potential for Combined Heat and Power in the Industrial Sector. Onsite Sycom Energy Corporation, Washington, DC.

Worrell, E., J-W. Bode, and J. De Beer. 1997. Analysing Research and technology Development Strategies: The 'ATLAS' Project Energy Efficient Technologies in Industry, Prepared for the European Commission, Utrecht University, The Netherlands.

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11. Gas Turbine – Drying

CHP Integration allows increased use of CHP in industry by using the heat in more efficient ways. This can be done by using the heat as a process input for drying. The fluegas of a turbine can often be used directly in a drier. This option has been used successfully for the drying of minerals as well as food products. Although NOx emissions of gas turbines vary widely, tests in The Netherlands have shown that the flue gases do not negatively affect the drying air and product quality, depending on the type of gas turbine selected (Buijze, 1998). To allow continuous operation, bypass of the gas turbines makes it possible to maintain the turbine and run the drying process (Buijze, 1998). A cement plant in Rozenburg, The Netherlands, uses a standard industrial gas turbine to generate power and to dry the blast furnace slags used in cement making. The Kambalda nickel mine in Australia uses four gas turbines of 42 MW each to dry nickel concentrate. The mine currently produces around 300,000 tones per year, saving 0.77 MBtu/short ton of concentrate. Another project in The Netherlands demonstrated the use of the flue gases from a gas turbine to dry protein rich cattle feed by-product. The excess flue gas is mixed with air and used directly for the drying process. The project was expected to result in savings of 12% of total onsite fuel consumption with a simple payback period of 2.5 years (under conditions in the Netherlands in 1995) (NOVEM, 1995).

The key asssumptions for the calculation of the potential are:
Amount of minerals to be dried: 60 Million metric tons (slags, phosphate ore, potash, and others). CHP-capacity is estimated to be around 130 kWh/ton, total capacity around 7.8 TWh. We then assume that 50% of this capacity can apply gas turbine driers. Technical potential is 3.9 TWh. Installed capacity (two shifts) is 0.7 GW

Capacity in food and related industries: estimated energy use is around 200 TBtu used for drying. Equivalent to 6.7 GW of energy. Assuming 35% efficiency for gas turbine and 50% for heat use, the power generation capacity is 4.7 GW. We assume that 25% of this capacity can apply gas turbines, or 1.2 GW. Assuming two shift operation and 95% availability will result in the production of 6.7 TWh.

Technical potential:	1.9 GW
Running time:	5548 Hours/year (2 shifts, 7 days/week, 95% availability)
Investment costs:	$970/kWe (Onsite, 2000), assuming 10 MW turbine on average.
Operation costs:	0.0055 $/kWh

References

Buijze, M. 1998. "Haalbaarheidsstudie naar Integratie van Twee Stuks Gasturbines" (Feasibility Study for Integration of two Gas Turbines), Netherlands Organization of Energy and Environment (Novem), Sittard, the Netherlands.

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12. Fuels Cells in the Chlorine-Alkaline Industry

Fuel cells generate direct current electricity and heat by combining fuel and oxygen in an electrochemical reaction. This technology avoids the intermediate combustion step and boiling water associated with Rankine cycle technologies, or efficiency losses associated with gas turbine technologies. Fuel to electricity conversion efficiencies can theoretically reach 80-83% for low temperature fuel cell stacks and 73-78% for high temperature stacks. In practice, efficiencies of 50-60% are achieved with hydrogen fuel cells while efficiencies of 42-65% are achievable with natural gas as a fuel (Martin et al., 2000). The main fuel cell types for industrial CHP applications are phosphoric acid (PAFC), molten carbonate (MCFC) and solid oxide (SOFC). Proton exchange membrane (PEM) fuel cells are less suitable for cogeneration as they only produce hot water as byproduct. PAFC efficiencies are limited and the corrosive nature of the process reduces the economic attractiveness of the technology. Hence, MCFC and SOFC offer the most potential for industrial applications.

Although PAFC is the most sold fuel cell system, MCFC and SOFC offer the most potential. Currently, several industrial facilities use MCFCs in Japan (Kirin brewery) and Germany (Michelin rubber processing) (Hoogers, 2003). These demonstration systems still cost around $11,000/kW. Stand-alone SOFCs have achieved an efficiency of 47%, and in combination with a gas turbine in a pressurized system, efficiencies of 53% (LHV) have been achieved (Hoogers, 2003). Unfortunately, the production costs of SOFCs are still high. Dow Chemical and GM will collaborate in the installation of a large-scale proton exchange membrane fuel cell (PEMFC) system (up to 35 MW), using hydrogen produced as a byproduct from chlorine production at Freeport, Texas. The Freeport facility of Dow Chemical is one the largest sites in the country producing about 1.9 Million tons of chlorine annually.

The U.S. produces about 12 Million tons of chlorine. Based on the typical hydrogen production rate of the chlorine-alkaline electrolysis process, the total hydrogen production is estimated at 35 TBtu. Assuming an efficiency of 52% (Kreutz and Ogden, 2000) total power generation is estimated at 5.3 TWh.

Technical potential:	0.6 GW
Running time:	8500 Hours/year (95% availability)
Investment costs:	$1500/kWe. Current costs are around $3000/kWe (Goldstein et al., 2003), but are expected to come down as the volume produced increases.
Operation costs:	0.008 $/kWh

References

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13. Black Liquor Gasification

In standard integrated Kraft mills, the spent liquor produced from de-lignifying wood chips (called black liquor) is normally burned in a large recovery boiler in which the black liquor combustion is used to recover the chemicals used in the delignification process. Because of the relatively high water content of the black liquor fuel, the efficiency of existing recovery boilers is limited. Gasification allows not only the efficient use of black liquor, but also of other biomass fuels such as bark and felling rests to generate a synthesis gas that after cleaning is combusted in a gas turbine or combined cycle with a high electrical efficiency. This increases the electricity production within the pulp mill. The technology is called black liquor gasification-combined cycle (BLGCC). The black liquor gasifier technology will produce a surplus of energy from the pulp process and opens the possibility to generate several different energy products for external use, i.e. electricity, heat and fuels. Gasifiers can use air or pure oxygen to provide the oxygen needed for the chemical conversions. We assume a (more expensive) oxygen-blown gasifier. The richer synthesis gas produced in an oxygen-blown gasifier allows easier combustion in a gas turbine. Furthermore, the process provides a natural separation of sulfur from sodium is provided that allows for advanced pulping, making it possible to enhance pulp productivity (Larson et al., 2000).

While increased fuel inputs are required for gasification systems, and increased electricity inputs are required (especially for gas compression in the combined cycle system), power efficiencies are much higher, thereby allowing for significant primary energy savings. Based on an electricity production capacity of 1740-1860 kWh/ton, and the performance of a typical Kraft-plant in the Southeastern United States, a plant will be able to export 220-335 kWh/ton of pulp (Larson et al., 2003). At the 2002 production level of chemical pulp, the U.S. pulp and paper industry could produce around 89.6 TWh of electricity, or double that of the current Tomlinson boiler system, or 50.2 TWh additional to the current power production in the pulp and paper industry.

Technical potential:	6050 MW
Running time:	8500 hours/year (98% availability)
Investment costs:	1070 \$/kWe
Operation costs:	0.006\$/kWh

References

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Larson, E.D., S. Consonni and R.E. Katofsky. 2003. A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry. Princeton University, Princeton, NJ.

14. Residue Gasification – Petroleum Refining

Because of the growing demand for lighter products and increased use of conversion processes to process a 'heavier' crude, refineries will have to manage an increasing stream of heavy bottoms and residues. Gasification of the heavy fractions and coke to produce synthesis gas can help to efficiently remove these by-products. The state-of-the-art gasification processes combine the heavy by-products with oxygen at high temperature in an entrained bed gasifier. The synthesis gas can be used as feedstock for chemical processes, hydrogen production and generation of power in an Integrated Gasifier Combined Cycle (IGCC). Entrained bed IGCC technology was originally developed for refinery applications, but is also used for the gasification of coal. Hence, the major gasification technology developers were oil companies like Shell and Texaco. The technology was first applied by European refineries due to the characteristics of the operations in Europe (e.g., coke was often used onsite). IGCC is used by the Shell refinery in Pernis (The Netherlands) to treat residues from the hydrocracker and other residues to generate 110 MWe of power and 285 tonnes of hydrogen for the refinery. Also, the IPA Falconara refinery (Italy) uses IGCC to treat visbreaker residue to produce 241 MWe of power (Cabooter, 2001). Interest among U.S. refiners has increased, and 3 U.S. refineries currently operate gasifiers, i.e., Motiva (Delaware City, DE), Frontier (El Dorado, KS) and Farmland (Coffeyville, KS). New installations have been announced or are under construction for the Sannazzaro refinery (Agip, Italy), Lake Charles, (Citgo, Louisiana) and Bulwer Island (BP, Australia).

With increasing production of lighter products the coke production at refineries is expected to increase to 116,000 tons/day in 2010 (Gray and Tomlinson, 2000). The net power production of a refinery based IGCC plant is estimated at 38-45%. Marano (2003) estimates net power production at 3,323 kWh/ton petroleum coke at an efficiency of 38.2%. The efficiency of an IGCC using heavy fuel oil is expected to be around 40% (Marano, 2003). Based on the 1999 coke production total power production can be 135.7 TWh/year, or 51 TWh over the baseline.

Technical potential:	15,960 MW
Running time:	8500 hours/year (98% availability)
Investment costs:	1780 $/kWe
Operation costs:	0.001$/kWh

References

Gray, D., G. Tomlinson. 2002. Potential of Gasification in the US Refining Industry. Report for U.S. Department of Energy, Washington, DC.

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15. Residue Gasification – Other Industries

Various industries produce low-grade fuels as a by-product of the production process. Currently, these low-grade fuels are combusted in boilers to generate steam or heat, or disposed of through landfilling. Often, this results in relatively less efficient use. Gasification offers opportunities to increase the efficiency of using low-grade fuels. In gasification, the hydrocarbon feedstock is heated in an environment with limited oxygen. The hydrocarbons react to form synthesis gas, a mixture of mainly carbon monoxide and hydrogen. The synthesis gas can be used in more efficient applications like gas turbine-based power generation or as a chemical feedstock. The technology not only allows the efficient use of by-products and wastes, it also allows low-cost gas cleanup (when compared to flue gas treatment). Various industries are pursuing the development of gasification technology, and are at different stages of development. Furthermore, gasification technology can also lead to more efficient and cleaner use of coal, biomass and wastes for power generation. Besides the pulp and paper and petroleum refining industries other industries with sufficient production of by-products that can be gasified are found in the food industry (e.g. bagasse in the sugar industry, nutshells, rice husk). The technology can also be used to process municipal solid waste with a higher efficiency than offered by incineration (e.g. the Thermoselect process developed in Switzerland produces over 700 kWh/tonne of waste), and is seeing commercial application in Japan.

In this description we focus on wastes from the food industry. A bagasse gasifier was installed in 1995 at the HC&S sugar mill on Maui (HI) producing a syngas with a low calorific value (Turn, 1997). The U.S. produces annually about 35 Million tons of sugarcane (2001), of which about 30% is bagasse. The bagasse is currently combusted in boilers and used for cogeneration. Gasification will increase the net power export by 101 kWh/ton cane (Larson et al., 2001). The technical potential for the cane sugar industry alone is estimated at 3.5 TWh. There are no estimates of the available amount of waste (e.g. nutshells, rice husk) in the other food industry that can be used for gasification. We suggest for this analysis that the technical potential in other industries is equivalent to 2 TWh.

Technical potential:	1,080 MW
Running time:	5100 hours/year (average 7 months/year)
Investment costs:	1600 $/kWe
Operation costs:	0.008$/kWh

References

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Turn, S. 1997. Demonstration-Scale Biomass Gasification Facility Operates on Bagasse. International Cane Energy News, July 1997, pp.4-5.

16. EPSI – VOC Control

Environmental and Power Systems International (EPSI) has developed an alternative pollution control technology for handling VOC emissions. The technology has the ability to generate electricity and useful thermal heat with a gas turbine, using the VOC-containing gases enriched with natural gas. The EPSI system is an alternative VOC abatement technology to regenerative thermal oxidizers (RTOs) with the following advantages over standard RTOs (GTI 2003):

- Shorter initial cold start-up time (5 minutes versus 1 to 8 hours)
- Recoverable heat for use by end-user (RTOs use their heat in the VOC abatement process)
- Electrical power generation
- Higher combustion temperature (which in combination with high residence time, assures more complete destruction of VOC)
- Smaller equipment footprint
- Lower major overhaul cost.

Technical potential:	13,500 MW. 60 TWh to 100 TWh (at 30% to 50% market share in 20 years respectively), or 10,000 – 17,000 MW total capacity.
Running time:	5870 Hours/year (67% capacity factor)
Investment costs:	Marginal cost of $360 to $4,000 /kW for a 525kWe system compared to a regenerative thermal oxidizer (RTO) VOC abatement system. The lower marginal cost estimate is derived by using a RTO system cost from a RTO end-user and the higher marginal cost estimate is obtained if the RTO manufacturer's system cost is used (GTI 2003). The EPSI cost is from the manufacturer.
Operation costs:	0.01 $/kWh

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17. Anaerobic Digestion Agriculture

Biogas systems are a waste management technique that can provide multiple benefits: removal of manure waste, reduction of odor, reducing disposal truck traffic and costs, reduction in spreading disposal costs, pathogen control and destruction, and protection of groundwater. Furthermore biogas digester systems can generate electricity and thermal energy to serve heating and cooling needs while providing financial profits. The byproducts of the digester system also include high-quality compost which can be used for crop fertilizer. Biogas systems are most suitable for farms that handle a large amount of manure as a liquid slurry or semi-solid with little or no bedding added. The type of digester should be matched to the type, design, and manure characteristics of the farm. There are five types of manure collection systems characterized by the solids content: raw, liquid (flushed), slurry (scrape), semi-solid (scraped), solid (left in pasture and not suitable). There are three types of digester systems: covered lagoon (used to treat and produce biogas from liquid manure), complete mix digester (heated engineered tanks for scraped and flushed manure), and plug flow (treat scraped *dairy* manure in 11% to 13% solids range). Swine manure does not have enough fiber to treat in plug flow digester. The products of anaerobic digestion are biogas and effluent. The effluent needs to be stored in a suitable sized tank. Recovered gas is 60-80% methane with heating value of 600-800 Btu/ft^3 (AgSTAR Handbook). This gas can be used to generate electricity or serve heating and cooling loads.

In January 2003 there were 40 anaerobic digesters operating in the U.S. with another 45 planned or under construction (AgSTAR Digest 2003). AgSTAR estimates that over 2,000 livestock facilities across the United States could cost effectively install biogas recovery systems (AgSTAR Handbook). Based on the average energy production from the 17 farms reporting electricity production from biogas in the AgSTAR Handbook survey an average estimate per farm of 700,000 kWh per year was obtained. This produces an estimate of 1.4 TWh per year for anaerobic digestion from livestock on farms. Digester system cost will vary depending upon the size and layout of the farm, type of animal, type of manure treatment and bedding used, and type of digester system installed, and the end-use application of the biogas (electrical generation or heat production only). Barriers to the adoption of biogas recovery systems include: poor technical and economic perception of digester systems based on initial system failures, and the lack of technical information and expertise.

Technical potential: 168 MW (AgSTAR Handbook)

Running time: 8300 Hours/year

Investment costs: $2000 (plug flow digester, AgSTAR Handbook)

Operation costs: $0.03/kWh (AgSTAR Handbook)

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18. Municipal Wastewater – Anaerobic Digestion

Wastewater treatment plants release biogas through the decomposition of organic matter. The biogas (mostly methane) can be captured and used to provide energy services either by direct heating or through the generation of electricity. Anaerobic digestion destroys pathogens and this method is used to generate biogas in many treatment plants. Typically the biogas is burned to produce heat to maintain the temperature of the digester process. Excess gas is then flared (Oregon State Energy Office 2004). This process destroys pathogens resulting in cleaner water and more benign solids.

The Madison Municipal Solid Waste District treats 42 million gallons of water every day at the Nine Springs Wastewater Treatment Facility. They have installed two 475 kW generators for $2 million. The savings are $370,000 per year in electricity and $75,000 in gas purchases before O&M costs are considered (Wisconsin's Focus on Energy 2002).

Of all the sites in the U.S. currently capturing biogas released at treatment plants and using it for electricity production there are only three sites that power a fuel cell to make electricity (Oregon State Energy Office 2004). One example of a wastewater treatment fuel cell biogas system is located in Portland Oregon. The facility handles 82 million gallons of wastewater per day. This one 200 kW capacity fuel cell will: cost $1.3 million, produce 1,400,000 kWh per year, save $60,000 per year, and offset 736 tons of greenhouse gas emissions annually (Oregon State Energy Office 2004).

There are 16,400 public wastewater treatment facilities in the US. There are another 23,700 "other" treatment facilities, which includes commercial or industrial facilities that treat their own water. These public sites each release about 2.5 Mgal/day on average of treated wastewater to the environment (USGS 1995). The non-public treatment facilities will be analyzed in the Industrial Biogas section.

The technical potential is estimated assuming 100% of the public plants generate electricity from biogas and they have the same rate of electrical generation that the Madison facility demonstrated (22.62 kW per Mgal/day of waste treated), generating 7.6 TWh per year. This assumes 94% availability (as at Oregon) and that the size of the treatment plant is linearly scalable with the amount of power capacity available from biogas.

Technical potential:	872 MW
Running time:	8200 Hours/year
Investment costs:	$2,000 per kW or $120,000 for an average wastewater plant
Operation costs:	0.01 $/kWh (est. from industrial biogas)

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19. Industrial Wastewater Treatment - Biogas

Industrial wastewater is typically treated by aerobic systems that remove contaminants prior to discharging the water. These aerobic systems have a number of disadvantages including high electricity use by the aeration blowers, production of large amounts of sludge, and reduction of dissolved oxygen in the wastewater which is detrimental to fish and other aquatic life. The decomposition of organic materials without oxygen results in the production of carbon dioxide and methane from the presence of anaerobic bacteria. This gas is called biogas and is 50% methane (CH_4) and a powerful greenhouse gas (21 times more potent of a greenhouse gas than CO_2) (EPA). This process is called anaerobic digestion and takes place in an airtight chamber called a digester. Biogas systems are a waste management technique with numerous benefits including: lower water treatment cost, reduction in odor, reduction in material handling and wastewater treatment costs, and protection of local environmental groundwater and other resources. In addition the biogas can be used as a supplemental energy source for thermal energy loads and the generation of electricity.

Any type of biological waste from plant or animals is a potential source of biogas. Some example industries include: pharmaceutical fermentation, pulp and paper wastewaters, fuel ethanol facility, brewery and yeast fermentation wastewater, coal conversion wastewater. Anaerobic digester biogas is comprised of methane (50%-80%), carbon dioxide (20%-50%), and trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen, and hydrogen sulfide. The most widely used technology for anaerobic wastewater treatment is the Upflow Anaerobic Sludge Blanket (UASB) reactor, which was developed in 1980 in The Netherlands. Industrial wastewater is directed up through the UASB reactor, passing through a "blanket" that traps the sludge. Anaerobic bacteria break down the organic compounds in the sludge, producing methane in the process. This type of anaerobic wastewater treatment is currently used predominantly in the paper and food industries, but some industries such as chemical and pharmaceuticals have also used this technology and its use is growing for municipal wastewater treatment. Globally, there are approximately 1500 anaerobic wastewater treatment plants (80 percent are UASBs), of which approximately 150 are in the U.S. (Martin et al. 2000).

The UASB technology is used around the world and the two leading UASB companies, Paques and Biothane, have installed several hundred facilities. Evaluations of anaerobic wastewater treatment facilities in the UK, Netherlands, Canada and U.S. show a wide range of costs and energy savings, with payback periods ranging from 1.4 years to 3.7 years (Martin et al., 2000). Currently, there are approximately 125 anaerobic wastewater treatment facilities in the U.S. There is great potential to increase the number of anaerobic wastewater treatment plants; some countries have 3 to 5 plants per million people, which implies that 750 to 1250 total plants could be installed in the U.S. For our analysis, we estimate that an additional 400 plants could be built by 2015. These plants can be used by a variety of industrial facilities, including papermaking, food processing, chemicals, pharmaceuticals, and distilleries. The market potential varies for these industries from 30 to 40 percent for the paper industry to 100 percent for processing of sugar, starch, and alcohol based on the size of the mills, types of mills, and their water consumption (Martin et al., 2000).

As of 1995, the last year the government kept track of these data, there were 23,700 non-public wastewater treatment facilities in the U.S. These include commercial and industrial facilities. Release information for these facilities is not available so the average capacity of the units is difficult to determine. A recent study (Martin et al., 2000) estimated the feasible potential for power production by 2015 at 150 GWh, based on a penetration rate of 33%. We assume a 60% penetration rate by 2025. The technical potential is equal to about 450 GWh.

Technical potential:	34 MW
Running time:	8000 Hours/year
Investment costs:	\$640/kWe (Martin et al., 2000)
Operation costs:	0.0055 \$/kWh
Payback period:	0.5 – 1.5 years (Martin et al., 2000)

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20. Landfill Gas

The decomposition of organic materials without oxygen in landfills results in the production of carbon dioxide and methane from the presence of anaerobic bacteria. In an non-controlled landfill, this would generate methane, a powerful greenhouse gas. Therefore, the landfill gas is often collected and flared, in which case the energy is not utilized. However, the gas can also be used for energy generation. The more common uses are: fuel gas for industrial boilers and electricity generation.

At many landfills, however, the gas is not recovered or flared. There are numerous barriers to economically utilizing landfill gas (EIA 1996): fluctuating gas prices, technology prices and performance risks, transportation costs of energy (when transported), air permits and changing regulations, as well as obtaining power contracts

The average size of LFG system is 3 MW with over 95% availability (EIA, 1996). There are 340 landfills, out of 6000, that currently capture landfill gas and turn it into energy. EPA estimates that there over 600 additional sites that could cost effectively capture methane and convert it into energy resources (EPA, LMOP 2004). Using this data 1800 MW of capacity could be obtained by fully utilizing the landfill gas in the U.S.

Direct end use of the gas for process heat and boiler fuel is the most economic use of landfill gas for sites within 1-2 miles. However, these projects accounted for only about 20% of the total energy recovery projects at landfills due in part to the lack of nearby customers for the fuel (Renewable Energy Annual, 1996). Over 70% of the landfill gas energy recovery projects generate electricity and 50% (of the total) use reciprocating engines (Thorneloe et. al). Electricity generation may be provided from reciprocating engines, gas turbines, and fuel cells. Engines are most economical for smaller projects from 1-3 MW and gas turbines for projects over 3 MW.

It's important to match the energy supply source with a nearby demand to increase the financial benefits from the project. The running time will be affected by the choice among the five options for recovering landfill gas and the type, location, and consistency of the demand. The estimated availability is 95% or 8,300 hours per year.

Technical potential:	1800 MW
Running time:	8300 Hours/year
Investment costs:	$1200/kWe
Operation costs:	0.016 $/kWh

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TOM CASTEN • PERSPECTIVE

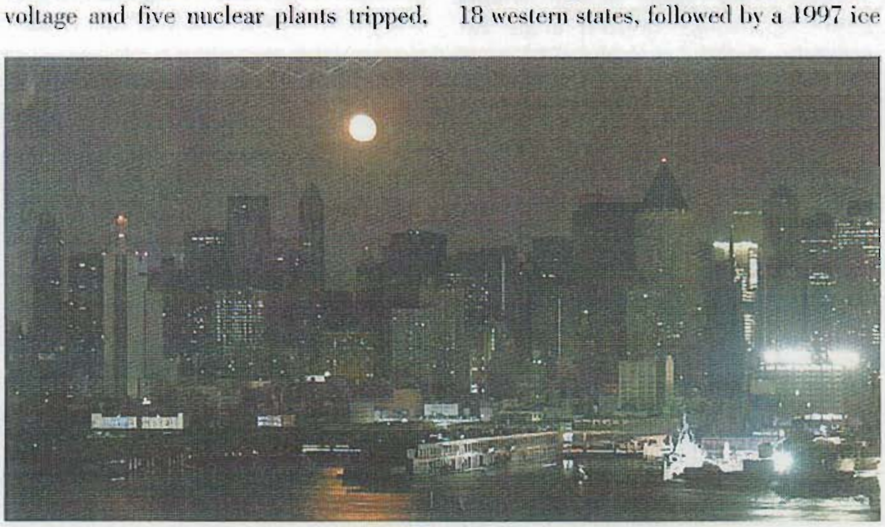
Fundamentally, there are two ways to prevent future electricity blackouts such as those that affected north-eastern US and parts of Canada in August. One is to spend billions on new wires; the other is to save money by encouraging the use of decentralized energy. Tom Casten says that the latter would not only be more successful, but would also deliver a host of other benefits.

Preventing blackouts

whether to spend or save our way out of the problem

On 14 August, at around 2:00 pm, a 31-year old, 650 MW Ohio power station failed. Transmission controllers struggled to route power from remote plants, overloading transmission lines. At 4:06 pm, a 1200 MW transmission line melted, starting a failure cascade. Lacking local generation, system operators could not maintain voltage and five nuclear plants tripped, forcing power to flow from more remote plants, and overloading regional lines. By 4:16 pm, the north-eastern US and Ontario, Canada lost power.

This was the eighth major North American outage in seven years, not counting five localized blackouts in New York City and Chicago. These area-wide failures began in 1996 with a blackout of 18 western states, followed by a 1997 ice storm in Quebec that knocked out much of New England, and a 1998 tornado that crippled mid-western power systems.



Upper West Side of Manhattan in virtual darkness, 14 August. Any lights were from emergency power supplies (AP/George Widman)

Then there was the California system failure in 2000, three ice storms in Oklahoma, and the August 2003 blackout. Pundits spread blame widely and call for massive investment in wires, while ignoring the fundamental flaw – the excessive reliance on central generation of electricity.

Power system problems are deeper than repeated transmission failures. Many US generating plants are old (average age 35 years), wasteful (33% delivered efficiency) and dirty (50 times the pollution of the best new decentralized energy plant). Centralized generation, besides requiring ugly, highly visible transmission lines, does not recycle its own by-product heat or extract fuel-free power from industrial waste heat and waste energy. This leaves two starkly contrasting ways to address blackouts:

- spend billions on new wires; this won't completely eliminate blackouts and will exacerbate other problems

- save money by encouraging decentralized energy; this will greatly reduce system vulnerability and deliver a host of other benefits.

DECENTRALIZED ENERGY COULD HAVE PREVENTED BLACKOUT

Years of active discouragement of all local power by the Ohio and Michigan utilities left the grid vulnerable to sagging voltage. Local generation can alter its output automatically to support voltage and enable lines to carry full design power.

In neighbouring Indiana, NiSource encouraged local power at the steel mills that it serves. It formed an unregulated subsidiary in 1994 that invested over US$300 million in 460 MW of decentralized power. The subsidiary, Primary Energy, built five projects that recycle waste heat and normally flared blast furnace gas. All of the power is consumed at the steel mills, easing transmission congestion and supporting local voltage.

The Indiana steel mills collectively save over $100 million per year by producing power with waste energy

Had the Ohio and Michigan steel mills recycled energy to produce on-site power, the plants would have supported the voltage and allowed the wires to carry more power to other consumers. All other things equal, the blackout would not have occurred.

Furthermore, such actions are good for the economy and the environment. The Indiana steel mills collectively save over $100 million per year by producing power with waste energy. These decentralized energy projects produce no incremental emissions and displace the emissions of a medium-sized coal-fired station operating around the clock. They are the environmental equivalent of roughly 2500 MW of new solar collectors operating for 20% of the time, on average.

These projects have not hurt the local utility, Northern Indiana Public Service Company, on balance. Yes, the utility sells less electricity to the mills, but steel production has risen, requiring more shifts and pumping up the local economy, increasing other electricity sales.

Decentralized energy (DE) has come of age. It employs proven central generation technologies and fuels but is located next to electricity and thermal loads. DE power goes directly to users, by-passing transmission, and DE plants recycle normally wasted heat, saving fuel and pollution. Local generation options are technically ripe, environmentally superior, and at least twice as efficient as average central generation.

Unfortunately, laws and regulations block decentralized energy. The industry and its regulators are caught in an overloaded, wire-entangled web that blocks innovation.

THE WIRING OF AMERICA

Central generation – long considered optimal – is an outgrowth of early generating technologies. Hydroelectric plants were inherently remote and early coal plants were noisy and dirty – not good neighbours. And coal plants required skilled operators, making them inappropriate for smaller users. For 80 years, power from remote plants – linked to the user by an ever growing set of wires – enjoyed cost advantages over local power.

By contrast, transportation required small engines that did not need skilled operators. Coal was tried for automobiles (the Stanley Steamer), but was soon displaced by oil-fired piston engines. For the first six decades of the 20th century, power technology evolved along two separate paths – coal-fired steam turbines for electricity and oil-fuelled piston engines for transportation. Over time, engine-driven power plants became cheaper to build, but required more expensive fuel and were only economic for back-up or remote electricity generation. Coal-fired steam power remained a better value for electricity into the 1960s.

Aircraft needs spurred another power generation technology, the combustion turbine. Pioneered near the end of the Second World War, early combustion turbines lacked efficiency but produced more power per unit weight than engines – critical to aircraft. Technology marched on. By the early 1980s, combined cycle gas turbine plants had become more efficient than the best steam power plants. To fill the gap being left by environmental pressure on coal plants, turbine manufacturers developed turbines suitable for stationary power generation.

By 1980, local gas turbine generation cost less to install and operate, required less net fuel and produced fewer net emissions than the best possible remote gas turbine generation and associated wires. Turbines are available from sub-megawatt to 200 MW in size, appropriate for local loads; the plants are all automated, clean and quiet. Generating power locally avoids capital required for transmission lines and eliminates transmission losses. Local power plants, unlike remote generation plants, can recycle by-product heat, reducing net fuel use and cost. The power industry embraced turbine technology, but clung to central generation, missing opportunities to save money and pollution with decentralized gas turbine generation.

Many other trends of the past 30 years also make decentralized energy attractive. The electrical efficiencies of turbine and piston engine power plants continue to increase. Transmission system losses of remotely generated power have increased from 5% to 9%, due to congestion. Computer controls enable unattended local generation based on waste gas and waste fuel.

The most efficient generation technology ever invented, back-pressure steam turbines, were historically limited by operator needs. With computer controls, these devices can economically extract power from waste heat, waste fuel, and steam pressure drop in virtually every large commercial and industrial facility. The US currently vents or flares heat, low-grade by-product fuel and steam pressure drop that could support 45–90 GW of back-pressure turbine generation capacity – some 6%–13% of the current US peak load.

Even coal-fired local power now beats the costs of power delivered from remote coal plants. Advances in fluidized bed boilers enable on-site production of heat and power with coal, biomass and other solid fuels in environmentally friendly plants. The limestone beds chemically bond with sulphur as calcium sulphate and limit combustion temperatures, reducing NOx formation. These clean coal plants, located near users, recycle heat to achieve 2.5 times the efficiency of remote coal plants.

Given all of these advances, an optimal power system would generate most power near users, using existing wires to shuttle excess power. Because electricity flows to the nearest connected users, regardless of the sales contract, locally generated power by-passes transmission lines.

Which brings us back to those long protected, overburdened, and vulnerable, failing wires that connect remote central plants to customers. Although the power industry finds itself in trouble, it clings to yesterday's optimal approach. Every stakeholder pays.

Power prices shot up by 65% from 1968 to 1984, needless environmental damage continues, many major industry players have declared bankruptcy or are close, banks are saddled with billions of non-performing loans to new central plants, and blackouts have become a way of life.

ELECTRICITY REGULATIONS AND INDUSTRY RESPONSES

Competition cleanses, discarding firms that cling to yesterday's technology. But the electricity industry has long been sheltered from competition. The US electricity industry's guiding signals have, since 1900, come from regulation rather than from markets. All 'deregulation' to date has left intact universal bans on private electric wires and many rules that penalize local power generation and protect incumbent firms from cleansing competition. History sheds light on how and why utilities and regulators have enshrined central generation and largely continued to oppose local power generation.

Electricity, commercialized in 1880, is arguably the greatest invention of all time. But early developers faced a big problem, finding money for wires to transport electricity to users who didn't think they needed it. To manage the risk, developers asked city councils for five-year exclusive franchises.

Thousands of small electricity companies sprang up; by 1900, there were 130 in Chicago alone. Greedy aldermen sold votes to extend franchises. Samuel Insull conceived of (and got) an Illinois state-granted monopoly in perpetuity. State monopolies spread.

States established regulatory commissions to approve capital investments and set rates that assured utilities of fair returns on capital. Under rate-based regulation, investments in efficiency improvements increase the rate base, but all savings go to customers. This approach does not allow utilities to profit from increasing efficiency. The misalignment of interests eventually caused industry stagnation, but in the early years, utilities chased efficiency to compete with candles, oil lamps, muscle power and self-generation.

Banks cheerfully loaned money to monopoly-protected utilities, fuelling a race to grow and acquire other systems. Power entrepreneurs borrowed huge sums to gain control over vast areas of the country. In 1929, the bubble burst; demand for electricity sagged, and over-leveraged trusts could not pay debt service. Utility bankruptcies deepened the Great Depression. Congress' response – the Public Utility Holding Company Act (PUHCA) – prevented utility amalgamation and assigned federal watchdogs to oversee finances. PUHCA blocked profit growth via acquisition or financial engineering. Profit-seeking utilities had two options: to sell more power, and to invest more capital in the rate base.

Both strategies favoured central generation over local power. Utilities sponsored research in electric appliances, motors and other novel uses of electricity that increased sales and provided significant public benefits. But they also fought local generation with every available means.

Electricity distribution companies have an understandable bias against generation that bypasses their wires and cuts potential profits. Utility monopolies long made it 'job one' to preserve the monopoly. The electric industry sponsored 'ready kilowatt' campaigns to win industry love, and skillfully coached (and paid) governments at every level to block decentralized energy.

For eight decades, central generation was the optimal technology. The regulatory approach delivered nationwide electrification and real prices fell by 98%. Electrification not only improved standards of living, but also played a strong role in positive social change.

Then, beginning in the late 1960s problems arose. Central generation ceased to be optimal, but the industry ignored local power innovations. Which brings us back to stakeholder costs.

THE GOOD TIMES END

By 1960, as competition withered away, utilities began pursuing questionable strategies. With no way to recycle by-product heat, fuel efficiency never moved beyond 33%. Utilities and their regulators rushed to convert many coal-fired power plants to oil, just in time for the OPEC embargo in 1973. Many utilities committed to build massive central plants that required up to 10 years to construct, far beyond safe planning horizons. When rising prices induced conservation, electricity load growth flattened and left the industry with massive over-capacity.

Then came nuclear. The utility industry committed vast sums, underestimating complexity and safety concerns. Some nuclear plants were built near budget, but others broke the bank. Cost overruns of

300%–500% were common. Long Island Lighting spent 19 years and $5 billion building Shoreham, only to have New York Governor Cuomo close the plant before it generated any power.

Figure 1 shows the rising real prices of US electricity after 1968. From 1970 to 1984, real electricity prices rose by 65%. Prices are given in 1996 dollars as reported at www.eia.doe.gov.

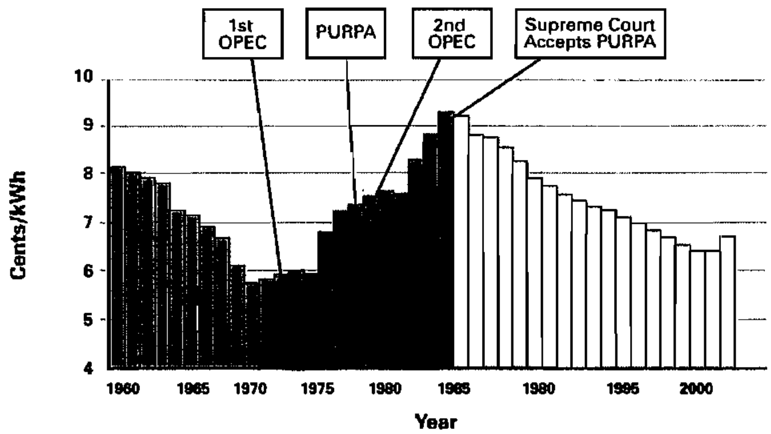


Figure 1. Real US electricity prices (1996 dollars)

Regulatory responses nearly got it right, flirting with local generation. The 1978 Public Utility Regulatory Policy Act (PURPA) sought to improve efficiency by exempting plants that recycled some heat from Federal Power Act regulations, and required utilities to buy power from these plants at avoided costs. Utilities fought PURPA to the Supreme Court, losing in 1984. But subsequent changes removed the pressure to build plants near users, and nascent DE was again driven back.

Next came Three Mile Island. State commissions, tired of nuclear cost overruns and rising prices, overturned the tacit regulatory compact. They challenged the prudence of utility investments in nuclear plants, claiming mismanagement. Historically friendly regulators ordered CEOs to remove billions of dollars from the rate base and reduce electricity prices. Utility shareholders took a bath.

The two changes did stop electricity price inflation; prices dropped to 1969 levels by 2000. But utility managements went into shock. They curtailed in-system investments, but still needed to put massive cash flow to work. Smarting from independent power producers' (IPPs') 'poaching' of their generation under PURPA, many utilities funded unregulated subsidiaries to poach generation in other territories. Never questioning the central generation mantra, utility subsidiaries began a disastrous race to build remote gas turbine plants, ignoring this strategy's vulnerability to rising gas prices. In the 13 months following May 2001, the 11 largest merchant power plant builders destroyed over $200 billion of market capitalization. Enron, NRG, and PSE&G and Mirant have since declared bankruptcy, while Dynegy, CMS and Mission struggle to pay creditors. Industry players that embraced gas-fired remote merchant plant development have seen their credit ratings lowered to junk status.

Major transmission failures did not start immediately. Spare transmission capacity, built in the days of compliant regulation, absorbed load growth until 1996, when a falling tree set off an 18-state blackout throughout the west. By then, load growth had made the non-growing transmission and distribution (T&D) system vulnerable to extreme weather (ice storms, tornadoes, hurricanes and drought induced hydro electricity shortages), human error and terrorists.

As costs and environmental concerns mounted, states began to experiment with partial deregulation, but never eased protection of wires, leaving utilities free to continue fighting DE by charging excessive back-up rates and denying access to customers. Commissions allowed generators to sell to retail customers, but then set postage stamp transmission rates, charging the same to move power across the street or across Texas. DE power, which only needs to move across the street, was left to pay the same transmission rates as power moving hundreds of miles through expensive transmission wires. Wholesale power prices give little recognition to the locational value of generation.

Environmental regulations also suppress decentralized generation. The 1976 Clean Air Act and subsequent amendments penalize efficiency. Almost all emission permits are granted based on fuel input, with no relationship to useful energy output. All new generation plants are required to install 'best available control technology', while existing plants retain 'grandfather' rights to emit at historic levels. These grandfather rights give economic immortality to old central stations and block innovation, and thus bear some responsibility for system failures.

The costs to all stakeholders from the central generation world view extend to other societal problems. The balance of payments suffers from needless fuel imports. The US demand for fossil fuel begets military adventures. Inefficient generation raises power costs, hurts industrial competitiveness and makes electricity generation the major source of greenhouse gas emissions, threatening entire ecosystems.

WHETHER TO SPEND OR SAVE OUR WAY OUT

There are two distinct paths to avoid more blackouts. Spend \$50–100 billion on new and upgraded transmission lines; or save money by removing barriers to decentralized energy.

The first path will raise electricity rates by 10%–15% and will exacerbate other problems. The second path will cost taxpayers nothing and mitigate other problems. To follow the second path, governments must:

- allow any provider to sell back-up power
- enact standard and fair interconnection rules
- void laws that ban third parties from producing and selling power to their hosts
- give every power plant identical emission allowances per unit of useful energy
- recognize the locational value of generation
- most importantly, allow private wires to be built across public streets.

These changes would transform the \$390 billion US heat and power business into a dynamic marketplace of competing technologies, and allow decentralized energy's competitive advantages to prevail. Utilities and IPPs will build new DE capacity to serve expected electricity load growth and reduce transmission congestion.

Ending central generation bias will upset vested interests and require a great deal of political effort, but the rewards for this leadership will be immense – lower power prices, reduced pollution, reduced greenhouse gas emissions, and a much less vulnerable national power system.

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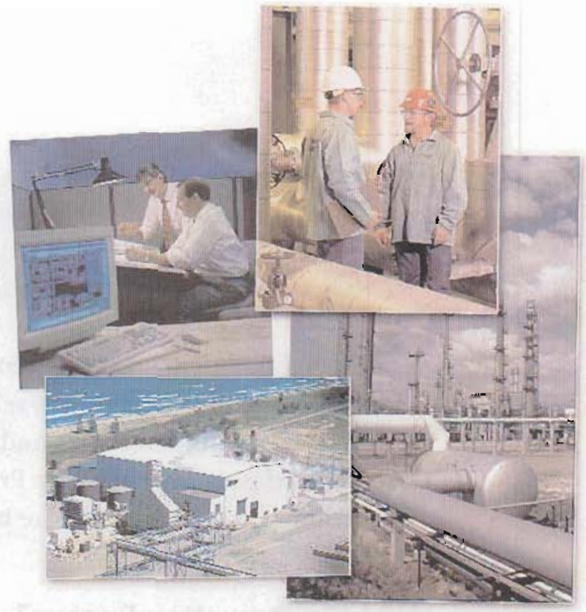

Improving Economic and Environmental Performance
Every Primary Energy energy recycling project must save money and reduce emissions. This is possible because we extract value from otherwise wasted energy and then tailor projects to customer's processes and local economics.

Industries We Serve
Process industries that can benefit from our expertise include:
- Metals
- Chemicals and Petrochemicals
- Refining
- Pulp and Paper
- Manufacturing
- Food and Beverage

How Primary's Unique Approach Helps You
Primary Energy dramatically improves traditional generation efficiencies or recycles your waste heat or fuel into heat and power. With us as an energy partner, customers can focus their knowledge, time and capital on their business while enjoying lower energy costs, improved reliability and rewards for environmental stewardship.

Award Winning
Customer's projects developed by Primary Energy have been recognized by federal and state government entities and trade organizations for their leadership in energy efficiency and pollution reduction.
- The U.S. Environmental Protection Agency and the U.S. Department of Energy awarded ENERGY STAR® Combined Heat and Power Awards for the Portside Energy and Lakeside Energy projects in northwest Indiana
- Four projects have received the Governor of Indiana's Award for Excellence in Pollution Prevention.
- Association of Iron and Steel Engineers awarded a Project Excellence Award to U.S. Steel Gary Works and Primary Energy for the Lakeside project.

Money Isn't All You're Saving

Financial Strength
Primary Energy has the financial strength and support needed to develop, build, own and operate reliable onsite Recycling Energy projects. In business since 1993, we currently have Recycling Energy assets with the total capacity to generate approximately 700 MW of electricity and 3.5 million pounds of steam. We are backed by American Securities Capital Partners ('ASCP'), a New York private equity firm (www.american-securities.com). ASCP is the merchant-banking arm of American Securities, L.P. which was founded in 1947.

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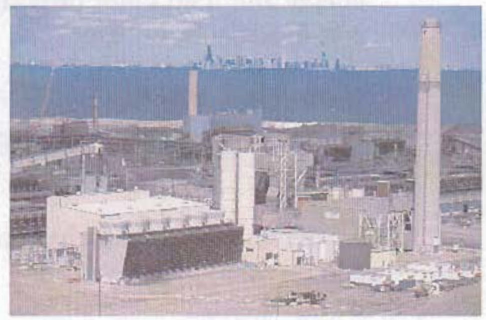
2-04

Primary Energy®

Corporate Overview

Primary Energy builds, owns and operates innovative Recycling Energy facilities in the U.S. serving our customers needs for reliable, low cost and environmentally sustainable electric and thermal energy. Our core competency is to capture and use waste energy and fuels with proven technologies and utilize traditional fuel more efficiently.



Our Recycling Energy projects generate thermal and electric energy on site with less reliance on the external power grid, minimizing costs and exposure to system vulnerabilities. Partnering with Primary Energy allows your team to focus on your core business, leaving energy supply to us.

What is Recycling Energy?

Recycling Energy is the efficient conversion of traditional fuels, waste fuels and waste heat into useful heat and power. Recycling Energy includes:

- recovering the heat or fuel value of exhaust streams normally vented or flared
- combined heat and power projects that efficiently use traditional and non-traditional fuels
- use of solid and liquid byproduct fuels
- extracting energy from pressure drop across thermal and gas distribution systems

Expertise
Construction Management
Technology Specification
Operations & Maintenance
Plant Optimization
Project Finance
Environmental and Safety
Fuel Management

Fuel
Waste Heat
Process Waste Gas
Byproduct Fuels
Coal
Oil
Natural Gas
Petroleum Coke

Experience Base

Technology
Gas Turbines
Heat Recovery Steam Generators
Steam Turbines
Industrial Boilers
Fluidized Bed Boilers
Reciprocating Engines

Experienced Team

Primary Energy's entire team has energy expertise and experience developing, financing, permitting, constructing, and operating energy projects utilizing a wide array of technologies and fuels. Many personnel have worked inside basic industries including steel, chemicals and heavy equipment manufacturing and utilities.

recycling energy™ CHP

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Cokenergy LLC

Project Description

Ispat Inland Inc. teamed with Primary Energy to address escalating energy costs and environmental concerns, by taking advantage of waste heat generated by a proposed onsite coke-making facility. Primary Energy collaborated with Ispat Inland's management and operations team along with Sun Coke (owner/operator of the coke battery) to develop a 95 MW waste heat recovery, combined heat and power (CHP) facility that provides electricity and process steam to Ispat Inland's steel-making operations.

Customer

ISPAT Inland Incorporated

Location

East Chicago, Indiana

Capacity

94 MW electric
930 kpph steam

Economic & Environmental Benefits

The combined coke-making and energy facility includes an integrated, first-of-its-kind CHP project using waste heat recovered from non-recovery coke batteries. The facility supplies one-fourth of Ispat Inland's total electrical requirements and 85% of its process steam needs, replacing onsite, coal-fired generation that was shut down soon after the facility came on-line. The Cokenergy project serves as the pollution control device for the coke battery, substantially reducing SO_2 and particulate emissions associate with coke production. The United States Environmental Protection Agency has determined the technical approach to represent Maximum Achievable Control Technology, setting a new industry standard for environmental performance. In addition, the use of waste heat to produce electricity instead of purchasing the power from regional electric utilities, displaces on average 13,000 tons of NOx, 15,500 tons of SO_2 and 5 million tons of CO_2 emissions per year.

Additional Project Details

The joint venture manages a variety of coals that are blended to obtain optimal fuel content and to manage for impurities and environmental performance. Heat recovered in the common stack from the three Blast Furnace No. 7 Stoves is used to dry the coal. Coal is pulverized and stored in a coal storage vessel under a nitrogen blanket. Pulverized coal is then conveyed to feed tanks and pneumatically blown into Blast Furnace No. 7 or trucked to No. 5 and No. 6 Blast Furnaces where it is also used to replace a portion of the coke requirements.

Commercial Operation

October 1998

Primary Energy develops, owns and operates on-site combined heat and power and recycled energy assets. We serve the energy needs of industrial, commercial and institutional customers with highly efficient, reliable, cost effective, environmentally sustainable, decentralized energy projects. Primary Energy is privately held and headquartered in Oak Brook, Illinois.

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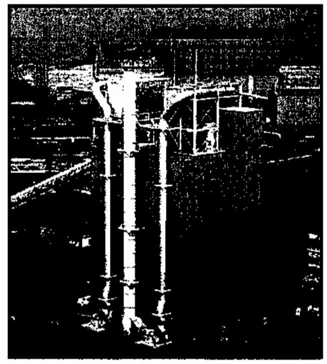
Primary Energy®

Harbor Coal LLC



Customer
ISPAT Inland Incorporated

Location
East Chicago, Indiana

Capacity
110 tons/hour

Project Description
Ispat Inland Inc. and Primary Energy identified an opportunity to reduce costs and improve the competitiveness of Ispat's blast furnaces by substituting pulverized coal for a significant portion of the coke, natural gas and fuel oil used in the iron production process. The two companies established a joint venture to build, own and operate an onsite pulverized coal processing and injection facility.

Economic & Environmental Benefits
The use of pulverized coal to replace a portion of the coke (also natural gas and fuel oil) in the blast furnace has substantial economic benefits. A ton of pulverized coal can be substituted for between .75 to .95 tons of coke but the price differential between coke and coal ranges from 2 to 4 times depending on the metallurgical coke and coal markets. The ability to use pulverized coal clearly provides a large financial savings to Ispat Inland. The project also uses waste heat from the blast furnace stoves to dry the coal, thus eliminating the need to burn natural gas and thereby further avoiding air emissions. Finally, blast furnace gas has a higher Btu content with coal utilization as opposed to coke, thus increasing the energy recovery potential for producing process steam and electricity.

Additional Project Details
The joint venture manages a variety of coals that are blended to obtain optimal fuel content and to manage for impurities and environmental performance. Heat recovered in the common stack from the three Blast Furnace No. 7 Stoves is used to dry the coal. Coal is pulverized and stored in a coal storage vessel under a nitrogen blanket. Pulverized coal is then conveyed to feed tanks and pneumatically blown into Blast Furnace No. 7 or trucked to No. 5 and No. 6 Blast Furnaces where it is also used to replace a portion of the coke requirements.

Commercial Operation
1993

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Primary Energy®

Ironside Energy LLC

Customer
International Steel Group

Location
East Chicago, Indiana

Capacity
50 MW electric
460 kpph steam

Project Description
International Steel Group (ISG) and Primary Energy partnered to develop additional on-site energy capacity, reducing energy costs and providing a more reliable, secure source of power and steam for Indiana Harbor Works. ISG needed to retire an existing onsite blast furnace gas recovery boiler and address an opportunity to recover additional blast furnace gas. Primary Energy installed and owns a 50 MW combined heat and power (CHP) facility comprised of a blast furnace gas recovery boiler and a condensing steam turbine.

Economic & Environmental Benefits
The Ironside Energy CHP facility allows ISG to capture and beneficially use practically all of the by product gas that would otherwise be flared, thereby producing useful electricity and reducing net pollution into the environment.

Additional Project Details
Primary Energy installed a 460,000-lb/hour boiler fired primarily on blast furnace gas from ISG's iron-making operations. The boiler is also capable of burning natural gas. Steam from the boiler is either distributed back to ISG as process steam or converted into electricity using a 50 MW full-condensing steam turbine generator. Primary Energy also constructed a low plume cooling tower and a new building housing the steam turbine generator, the boiler, and a control room.

Commercial Operation
December 2002

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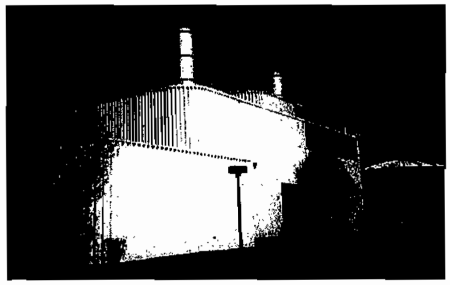
EF Kenilworth LLC



Project Description

Primary Energy's Kenilworth facility is a 30 MW combined heat and power (CHP) project which serves the world headquarters complex of global healthcare company Schering-Plough Corporation. The majority of the electricity and all of the steam produced by the facility are sold to Schering-Plough while electrical output in excess of Schering's requirements is sold to Jersey Central Power & Light Company. In addition to supplying steam and power from the CHP facility, Primary Energy supplies additional steam to Schering-Plough from an onsite boiler house which includes four gas-fired boilers.

Customers

Schering-Plough Corporation-
steam and electricity

Jersey Central Power & Light Company-
electricity

Location

Kenilworth, New Jersey
(located nine miles southwest of Newark, NJ)

Capacity

30 MW electric
380 kpph steam

Economic & Environmental Benefits

The Kenilworth CHP facility and the onsite boiler house provide approximately 90% of Schering-Plough's annual electrical requirements and over 100% of their annual steam demand. The CHP facility operates with water injection for Nox control and is equipped with a catalyst to reduce carbon monoxide emissions. The production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over 190 tons of NOx, 750 tons of SO_2 and 13,000 tons of CO_2 per year. In addition, Schering-Plough benefits economically from both lower energy costs and increased reliability.

Additional Project Details

The CHP facility incorporates a 23 MW GE LM2500 gas turbine with an unfired heat recovery steam generator (HRSG) and a 7 MW condensing-extraction steam turbine. The gas turbine is principally fired on natural gas with #2 fuel oil available for backup. Primary Energy recovers and recycles exhaust heat from the gas turbine to produce further amounts of useful steam and power. Schering-Plough's 75-acre Kenilworth campus contains their worldwide headquarters, primary R&D Center (a facility of over a million square feet) and a pharmaceutical manufacturing/processing center. The campus houses more than 3,500 employees. Jersey Central Power & Light provides electrical energy to 2.7 million people across the state of New Jersey.

Commercial Operation

1989

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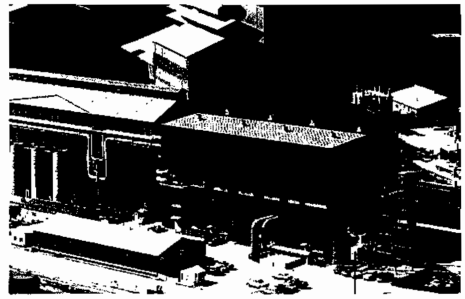
Primary Energy®

Lakeside Energy LLC



Project Description

United States Steel and Primary Energy identified an opportunity to replace 60 MW of aging onsite electric generation with a modern 161 MW combined heat and power facility. Primary Energy, who owns the facility, had the responsibility for the design and construction of the unit, while USS Gary Works upgraded it's blast furnace gas recovery boilers to enhance the consumption of byproduct fuel. The condensing-extraction turbine generator produces electricity and process steam for the USS Gary Works steel producing facility.

Customer

United States Steel Corporation

Location

Gary, Indiana

Capacity

161 MW electric

Economic & Environmental Benefits

The modernized CHP facility recovers and uses 95% of the blast furnace gas available from the plant's iron production to provide more than 40% of the electric and all of the process steam for the primary operations of the facility. The USS Gary Works boilers can burn a combination of blast furnace, coke oven and natural gas, providing flexibility to produce additional electricity based on fuel and electric prices. USS Gary Works estimates that they are saving millions of dollars a year in energy costs due to the Lakeside Energy facility, enhancing the Corporation's competitive position in the global steel market. In addition, the use of blast furnace gas to produce electricity instead of purchasing the power from regional electric utilities, displaces on average 3,000 tons of NOx, 3,300 tons of SO_2 and 1.1 million tons of CO_2 emissions per year.

Additional Project Details

The Lakeside Energy facility is interconnected with the Gary Works existing 69 kV transmission system. The combined turbine generator performance has had an availability of 99.8% since commencing commercial operation.

Awards

Lakeside Energy LLC was awarded the 1999 Project Excellence Award by the Association of Iron and Steel Engineers (AISE) and also is a recipient of the 2000 Indiana Governor's Award for Excellence in Pollution Prevention. In addition, USS Gary Works received the 2001 Energy Star® Combined Heat and Power Award from the U.S. Environmental Protection Agency and the U.S. Department of Energy.

Commercial Operation

April 1997

Money Isn't All You're Saving

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Primary Energy®

Marine Corps Recruit Depot CHP Facility

Applied Energy LLC

Project Description

Primary Energy's Marine Corps Recruit Depot (MCRD) CHP Facility is a 25 MW combined heat and power (CHP) plant which serves the Marine Corps Recruit Depot and the Anitisubmarine Warfare (ASW) Training Complex in San Diego. The Depot is one of two principal Marine recruiting and training bases in the country. Steam produced by the CHP plant and two auxiliary boilers is used to meet the energy requirements of a network of 245 buildings on the Depot. All the electricity produced by the CHP plant is sold to San Diego Gas & Electric Company under long-term power purchase agreements.

Customers

U.S. Navy-electricity and steam

San Diego Gas & Electric Company-electricity

Location

San Diego, California

Capacity

25 MW electric

285 kpph

Economic & Environmental Benefits

The MCRD CHP facility provides 100% of the Depot's annual steam requirements and the requirements for the ASW schools. The CHP plant is equipped with selective catalytic reduction technology and a carbon monoxide (CO) catalyst which substantially reduces nitrogen oxide (NOx) and CO emissions. The production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over tons of 200 NOx, 400 tons of SO_2 and 140,000 tons of CO_2 per year. In addition, the Depot and SDG&E ~~increased local reliability.~~

Additional Project Details

The CHP facility incorporates a GE LM2500 gas turbine, a duct-fired HRSG, a 2.5 MW condensing steam turbine and two additional auxiliary boilers. The primary fuel is natural gas with #2 fuel oil used for backup. The Marine Corps Recruit Depot occupies just under 400 acres and houses nearly 1,500 active duty personnel, their family members, reservists and retired military personnel. Base facilities encompass nearly 2.6 million square feet under roof. The site was developed in 1919 and first used as a base by the Corps in 1924. San Diego gas & Electric is California's third largest investor owned utility serving the southern portion of the state including all of San Diego.

Commercial Operation

1989

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Naval Station CHP Facility
Applied Energy LLC

Project Description
Primary Energy's Naval Station CHP Facility is a 46.5 MW combined heat and power (CHP) plant which serves the U.S. Navy's San Diego Naval Station (Navsta) on the eastern edge of San Diego Bay. Steam produced by the CHP plant and 2 auxiliary boilers is supplied to the Navy and is used within ships berthed along 12 miles of piers and also for the substantial network of buildings across the 1,000 acre site. Electric output is sold to San Diego Gas & Electric Company (SDG&E) under a long-term power purchase agreement.

Customers
U.S. Navy-electricity and steam
San Diego Gas & Electric Company-electricity

Location
San Diego, California

Capacity
46.5 MW electric
387 kpph steam

Economic & Environmental Benefits
The Naval Station CHP facility provides 100% of Navsta's annual steam requirements and has the ability to provide electricity directly to the Navy if required, adding reliability to this critical Navy facility. The CHP plant is equipped with selective catalytic reduction technology and a carbon monoxide (CO) catalyst which substantially reduces nitrogen oxide (NOx) and CO emissions. The production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over 400 tons of NOx, 800 tons of SO_2 and 250,000 tons of CO_2 per year. In addition, the Navy and SDG&E benefit from both lower energy costs and increased local reliability.

Additional Project Details
The CHP facility incorporates a GE Frame 6 combustion turbine, a duct-fired HRSG, a 10 MW condensing-extraction steam turbine and two additional auxiliary boilers. The primary fuel is natural gas with #2 fuel oil used for backup. Constructed in 1919 as a docking and repair base, Naval Station has grown into the Navy's largest surface force support installation. The base is homeport to nearly 100 ships including support vessels for aircraft carriers, submarines and other specialized units. The base sustains a population of more than 42,000 military and civilian personnel, while the workforce approaches 48,000 daily. San Diego Gas & Electric is California's third-largest investor owned utility serving the southern portion of the state including all of San Diego.

Commercial Operation
1989

recycling energy CHP

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North Lake Energy LLC

Customer
ISPAT Inland Incorporated

Location
East Chicago, Indiana

Capacity
75 MW electric

Project Description
Ispat Inland Inc. has historically produced a significant portion of their electricity requirements using onsite generation resources. Primary Energy worked with Ispat Inland to identify an additional opportunity to capture and recycle heat from Ispat's principle blast furnace (No. 7), producing up to 75 MW of electricity.

Economic & Environmental Benefits
The North Lake Energy project is capable of supplying more than 20% of Ispat Inland's electricity requirements using an onsite waste fuel that had principally been flared. Primary Energy built and owns the project while Inland Ispat delivers steam from the existing blast furnace gas recovery boilers. This facility has reduced energy costs substantially compared to purchased power alternatives while increasing reliability of the electric energy supply for Ispat Inland's plant operations. In addition, by using previously flared blast furnace gas to produce electricity instead of purchasing the power from the local electric utility, the project reduces regional air emissions on average by 1,300 tons of NOx, 1,500 tons of SO_2 and 490,000 tons of CO_2 emissions per year.

Additional Project Details
Exhaust gas from Blast Furnace No. 7 has historically been used to produce process steam for Ispat Inland's steelmaking operations. Gas supply however exceeded process steam requirements, which required excess gas to be flared. Primary Energy installed a full-condensing steam turbine generator to capture and use the full value of previously flared blast furnace gas. The facility connects to Ispat Inland's existing 69 KV transmission system.

Awards
North Lake Energy has received an Excellence in Pollution Prevention Award from the Governor of Indiana.

Commercial Operation
May 1996

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North Island Facility

Applied Energy LLC

Project Description

Primary Energy's North Island CHP Facility is a 40 MW combined heat and power (CHP) plant which serves the U.S. Navy's North Island Naval Air Station on Coronado Island. A small portion of the electric output and all of the steam produced by the facility are sold to the Navy while the remaining electricity is sold to San Diego Gas & Electric Company (SDG&E). The CHP facility includes a combustion turbine, heat recovery steam generator (HRSG), a steam turbine generator and two auxiliary boilers. The Navy's Naval Air Station occupies approximately 2,000 acres of the north section of Coronado Peninsula and includes an airfield, deep-draft port facilities, and extensive aerospace manufacturing facilities.

Customers

U.S. Navy-electricity and steam
San Diego Gas & Electric Company-electricity

Location

San Diego, California

Capacity

40 MW electric
390 kpph steam

Economic & Environmental Benefits

The North Island CHP facility provides approximately 100% of the Navy's annual steam requirements for use on land as well as for ships berthed at the base. In addition, the electrical output of steam turbine is dedicated for the Navy's use and meets a portion of their annual electrical requirements. The production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over 300 tons of NOx, 6[illegible]0 tons of SO_2 and 220,000 tons of CO_2 per year. In addition, the Navy and SDG&E benefit economically from both lower energy costs and increased reliability.

Additional Project Details

The CHP facility incorporates a GE LM5000 gas turbine, a duct-fired HRSG, a [illegible]4MW condensing extraction steam turbine and 2 additional auxiliary boilers. The primary fuel is natural gas with #2 fuel oil used for backup in one of the auxiliary boilers. North Island enjoys long-term power purchase agreements for both electric and steam output. Naval Air Station, North Island supports more than [illegible]35 aircraft. Considered the most diversified and experienced naval aviation depot, North Island provides engineering, calibration, overhaul and repair services to 3 nuclear aircraft carriers, fixed wing aircraft and helicopters, West coast Navy deep submergence rescue ships and some of San Diego's surface forces. With all ships in port, base population climbs to more than 30,000 active duty, selected reserve military and civilian personnel. Factories at the Naval Aviation Depot employ an additional 3,800 civilians. North Island was first commissioned in 1917 and remains an integral component in naval operations, having been targeted for expansion to accommodate growth in the Navy's nuclear powered carrier fleet. San Diego Gas & Electric is California's third largest investor owned utility serving the southern portion of the state including all of San Diego. Located at the southwestern edge of the WSCC grid, the area has an identified need for additional local generation to reduce its reliance upon remote resources. North Island is ideally suited to provide grid stability to the Coronado Peninsula in the event SDG&E loses its underbay transmission cables.

Commercial Operation

1989

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recycling energy™ CHP

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Primary Energy®

EF Oxnard LLC

Project Description

Primary Energy's Oxnard facility is a 48.5 MW combined heat and power (CHP) project which serves the headquarters and principal refrigerated processing operations of Boskovich Farms, Inc., an integrated vegetable and fruit grower, processor, packager and refrigerated/frozen foods storage company. Steam produced by the Oxnard CHP facility is used to drive an ammonia absorption refrigeration unit to refrigerate or freeze fresh strawberries and vegetables prior to distribution throughout the western U.S. The electrical output of the CHP facility is sold to Southern California Edison under a long-term firm power purchase agreement.

Customers

Boskovich Farms-steam/refrigeration
Southern California Edison-electricity

Location

Oxnard, California

Capacity

48.5 MW electric
120 kpph steam/ 800 tons refrigeration

Economic & Environmental Benefits

The Oxnard CHP facility provides a substantial portion of Boskovich's annual refrigeration requirements. The CHP facility's heat recovery steam generator (HRSG) is equipped with selective catalytic reduction technology that substantially reduces nitrogen oxide (NOx) emissions. The combination of environmental controls and the production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over 110 tons of NOx, 240 tons of SO_2 and 58,000 tons of CO_2 per year. In addition, Boskovich and Southern California Edison benefit economically from both lower energy costs and increased reliability.

Additional Project Details

The CHP facility incorporates a natural-gas fired, steam-injected GE LM5000 gas turbine with a duct-fired HRSG and a low temperature anhydrous ammonia absorption refrigeration system. The recently upgraded 74,000 sq ft state-of-the-art Boskovich Farms complex is the cornerstone of the family owned and operated company that has been in business since 1915. Southern California Edison is one of California's largest electric utilities, serving 4.6 million customers.

Commercial Operation

1990

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recycling energy - CHP

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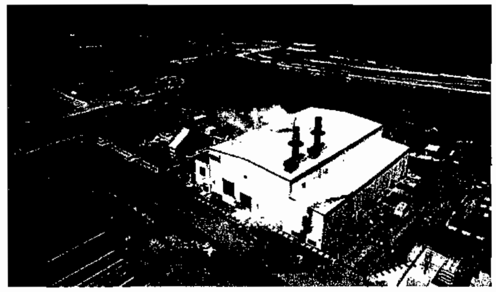
Primary Energy®

Portside Energy LLC



Project Description

United States Steel (formerly National Steel) and Primary Energy identified an opportunity to replace an existing onsite boiler house with a state-of-the-art combined heat and power facility (CHP). Primary Energy built, owns and operates a 63 MW facility that supplies process steam, hot softened water and electricity to USS's Midwest Plant operations.

Customer

United States Steel Corporation

Location

Portage, Indiana

Capacity

500 kpph steam
330 mmbtu/hr hot water

Economic & Environmental Benefits

The CHP facility supplies 100% of the thermal energy needs and the majority of the electrical energy needs of the Midwest Plant. The combined impact of replacing steam production using natural gas/fuel oil and the simultaneous production of electricity also has the effect of reducing regional emissions by an average of 1,500 tons of NOx, 2,500 tons of SO_2 and 380,000 tons of CO_2 per year.

Additional Project Details

The CHP facility includes a 44 MW General Electric (GE) combustion turbine generator, a 19 MW GE steam turbine generator, a 150,000-lbs/hr once-through steam generator, two 175,000-lbs/hr auxiliary boilers and a boiler water treatment system. Also included is a 3,000 gpm, 160°F hot softened water system that is used by the finishing and coating facilities enabling significantly reduced defects and improved product quality.

Awards

Portside Energy is a recipient of the 2000 Indiana Governor's Award for Excellence in Pollution Prevention. In addition, U. S. Steel received the 2001 Energy Star® Combined Heat and Power Award from the U.S. Environmental Protection Agency and the U.S. Department of Energy for this innovative project.

Commercial Operation

September 1997

Energy Star — Money Isn't All You're Saving

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recycling energy - CHP

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Primary Energy®

Thermo Power & Electric, LLC

Project Description

Primary Energy's Thermo Power & Electric, LLC (Primary Energy Thermo) CHP Facility is a 72.5 MW combined heat and power (CHP) plant which serves the University of Northern Colorado. Steam produced by the CHP plant is converted to hot water which serves the district heating needs of the 240 acre campus. Electric output is sold to Public Service of Colorado (PSCo), a wholly owned subsidiary of Xcel Energy under a long-term power purchase agreement.

Economic & Environmental Benefits

The Primary Energy Thermo CHP facility provides a substantial portion of UNC's annual hot water requirements. The plants' combustion turbines are steam-injected to reduce nitrogen oxide emissions. The production of both useful electricity and thermal energy from the CHP facility has the effect of reducing regional emissions by an average of over 140 tons of NOx, 260 tons of SO and 63,000 tons of CO_2 per year. In addition, the University and PSCo benefit from both lower energy costs and increased local reliability.

Customers

University of Northern Colorado-hot water
Public Service Company of Colorado-electricity

Location

Greeley, Colorado

Capacity

72.5 MW electric
200 kpph steam

Additional Project Details

The CHP facility incorporates two GE LM5000 combustion turbines with two unfired HRSG's, a 12 MW condensing-extraction steam turbine and steam/hot water heat exchangers. The facility is fueled exclusively by natural gas. The University of Northern Colorado, located one hour north of Denver, serves a population of 11,000 students and 3,500 employees; the campus includes 58 separate buildings. Xcel Energy is one of the largest combination electricity and natural gas energy companies in the U.S., operating in 11 western and midwestern states.

Commercial Operation

1988

Primary Energy develops, owns and operates on-site combined heat and power and recycled energy assets. We serve the energy needs of industrial, commercial and institutional customers with highly efficient, reliable, cost effective, environmentally sustainable, decentralized energy projects. Primary Energy is privately held and headquartered in Oak Brook, Illinois.

recycling energy · CHP

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Primary Energy®

NEWS

For Immediate Release

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Primary Energy Completes Acquisition of Six (6) Combined Heat and Power (CHP) Projects in California, Colorado and New Jersey

Oak Brook, Illinois, Jan 11, 2005 – On December 31, 2004, Primary Energy Holdings LLC (Primary Energy) completed its previously announced acquisition of six (6) combined heat and power (CHP) facilities located in California, Colorado and New Jersey from entities controlled by Reservoir Capital Group, a private investment firm. The six projects have a combined electric generating capacity of 270 megawatts and can produce almost 1.7 million pounds per hour of steam. The facilities provide thermal energy to industrial, government and university customers while selling electricity to local electric utilities under long-term contracts. All of the operating and management staff associated with the projects has joined Primary Energy.

Concurrent with the acquisition, Primary Energy completed a $165 million term loan, led by Lehman Brothers, proceeds of which are being used for general corporate purposes including the acquisition of the CHP projects.

Primary Energy, based in Oak Brook, Illinois, develops, owns and operates energy recycling projects serving industrial, commercial and institutional customers throughout North America. With this acquisition the company has recycling energy assets with the capacity to generate more than 700 MW of electricity and more than 3.5 million pounds per hour of steam. More information about the company is available at www.primaryenergy.com. The majority owner of Primary Energy is American Securities Capital Partners, LLC (ASCP), a New York private equity firm (www.american-securities.com). ASCP is the merchant-banking arm of American Securities, L.P., which was founded in 1947.

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NEWS

For Immediate Release

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Mark C. Hall
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Primary Energy To Acquire Six (6) Combined Heat and Power (CHP) Projects In California, Colorado and New Jersey

Oak Brook, Illinois, July 21, 2004 – Primary Energy Holdings LLC (Primary Energy) announced today that it has signed a definitive purchase agreement with entities controlled by Reservoir Capital Group (Reservoir), a private investment firm, to acquire six (6) combined heat and power (CHP) facilities located in California, Colorado and New Jersey for a total price of approximately $190 million, including equity, debt and operating lease obligations. The six projects have a combined electric generating capacity of 270 megawatts and can produce almost 1.7 million pounds per hour of steam. The facilities provide thermal energy to government, industrial and university customers while selling electricity to local electric utilities under long-term contracts.

"We are very pleased to have reached agreement with Reservoir to acquire these projects" said William B. Johnson, Executive Vice President of Primary Energy, responsible for acquisitions. "These are long-term contracted assets in key energy markets, providing Primary Energy with customer diversity and an excellent platform for future growth."

"We are equally pleased that the outstanding operations staff currently operating the facilities will be joining Primary Energy and will aggressively pursue our objective of increasing energy efficiency to improve value to its customers" stated Thomas R. Casten, Chairman and CEO of Primary Energy. "We expect a smooth transition and look forward to serving our new customers."

The projects include:

- Three Defense Department projects in San Diego, located at the San Diego Naval Station (48 MW), the Coronado Naval Air Station (40MW) and the Naval Training Center/ Marine Corps Recruit Depot (25 MW). Steam is delivered to military installations; electricity is sold to San Diego Gas and Electric, a subsidiary of Sempra Energy.

- One 48 MW project in Oxnard, California, that provides thermal energy to Boskovich Farms, a food processing and cold storage facility, and electricity to Southern California Edison, a subsidiary of Edison International.

- One 79 MW project in Greeley, Colorado, that provides thermal energy to the University of Northern Colorado , and electricity to Public Service of Colorado, a subsidiary of Xcel Energy.

- One 30 MW project in Kenilworth, New Jersey, that sells electricity and thermal energy to Schering Plough at its worldwide headquarters and research and development facility, and sells additional electricity to Jersey Central Power and Light Company, a subsidiary of First Energy.

Primary Energy, based in Oak Brook, Illinois, develops, owns and operates recycling energy projects for industrial, commercial and institutional customers throughout North America. With this acquisition the company has recycling energy assets with the capacity to generate more than 700 MW of electricity and more than 3.5 million pounds per hour of steam. The majority owner of Primary Energy is American Securities Capital Partners, LLC (ASCP), a New York private equity firm (www.american-securities.com). ASCP is the merchant-banking arm of American Securities, L.P., which was founded in 1947.

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CHP

NEWS

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For Immediate Release

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American Securities Capital Partners, Private Power Complete Acquisition of Primary Energy Assets

NEW YORK, October 20, 2003 –American Securities Capital Partners LLC ("ASCP"), a New York private-equity investment firm, and Private Power LLC ("Private Power"), a privately held developer, owner and operator of on-site combined heat and power, recycled energy and district energy projects, announced today they had completed the acquisition of six operating subsidiaries of Primary Energy, Inc. , a subsidiary of NiSource Inc. (NYSE: NI).

The value of the transaction was approximately $335 million in cash and assumed debt.

The six subsidiaries operate facilities that have the capacity to generate approximately 900 megawatts of combined electric and thermal energy by recycling blast furnace gas and waste heat from coke ovens and gas-fired power generation. The facilities operate under long-term contracts with United States Steel, Ispat Inland Inc. and International Steel Group and are all located in Northern Indiana.

The acquisition was completed through a newly formed company called Primary Energy Holdings LLC ("Primary Energy"), based in Oak Brook, Illinois. ASCP will hold a controlling interest in the new enterprise.

Thomas R. Casten, founder of Private Power and chief executive officer of Primary Energy Holdings, said, "Our strategy will be to build on the Primary Energy assets to acquire and develop other energy recycling projects that generate profits and at the same time reduce our customers' operating costs, fuel use and pollution. We have great confidence in the Primary Energy banner, given the industry's recognition of the innovative nature, the efficiency and the effectiveness of the projects we are acquiring."

Casten said that Primary Energy Holdings was actively seeking additional opportunities to acquire and/or develop on-site combined heat and power, recycled energy and district energy projects.

Most of the top Primary Energy Inc. managers will join the new "Primary Energy," including Joe Turner, who will serve as executive vice president of Primary Energy Holdings and president of its operating subsidiary, Primary Energy Steel.

"We welcome the opportunity to join forces with Private Power and ASCP," said Turner. "Working with the team at Primary Energy Holdings, we will be able to continue to provide value-added solutions to our host steel plants, and pursue additional development opportunities that leverage our expertise in combined heat and power projects."

Michael G. Fisch, president of ASCP, said, "We are fortunate to be able to partner with the experienced team from Private Power to acquire distributed power-generation assets. As the first acquisition, Primary Energy is a perfect fit with this strategy."

The transaction includes:

- Cokenergy, Inc., a 95-MW CHP facility that converts waste coke oven heat to provide electricity and process steam to Ispat Inland's steelmaking operations in East Chicago, Ind.;
- Lakeside Energy Corp., a 161-megawatt (MW) CHP facility that uses steam produced from blast furnace gas to provide electricity and process steam to United States Steel's Gary Works in Gary, Ind.;
- North Lake Energy Corp., a 75-MW steam turbine generator that uses steam produced from blast furnace gas to provide electricity to Ispat Inland in East Chicago, Ind.;
- Ironside Energy LLC, a 50-MW facility that uses steam produced from blast furnace gas to provide steam and electric power to International Steel Group's (ISG) operations in East Chicago, Ind.;
- Portside Energy Corp., a 63-MW trigeneration facility that supplies process steam, hot softened water and electricity to United States Steel's steel finishing operations in Portage, Ind.;

- Harbor Coal Company, a 50 percent general partner in PCI Associates, which uses waste heat from blast furnace stoves to dry pulverized coal for injection into Ispat Inland's blast furnace in East Chicago, Ind.

American Securities Capital Partners LLC is the private-equity investment arm of American Securities, a family office founded in 1947 by the late William Rosenwald to manage his share of his family's Sears Roebuck fortune. ASCP is currently investing its third private-equity investment fund with outside investors, and manages over $1 billion of equity capital on a discretionary basis. Additional information is available at ASCP's web site, www.american-securities.com.

Private Power, now renamed Primary Energy Holdings (Primary Energy), is based in Oak Brook, Illinois, and develops, owns and operates decentralized generation projects for industrial, commercial and institutional customers throughout North America. Additional information is available at www.privatepower.net.

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