Energy Conversion Technologies

1.0 Introduction

In these and subsequent notes, we will describe the infrastructure that is available to be considered in the generation and planning functions. We classify this information by

- Energy conversion, transport, and storage
- Technologies available now, and those likely to be available in the future.

Some qualifications:

- We primarily consider only technologies which facilitate the conversion, transport, and storage of bulk (large) quantities of energy. There will be one exception to this: small-scale distributed generation.
- By “energy conversion,” we mean the conversion of energy into some form into electric energy.
- By “available now,” we mean that the technology is available now at a cost that is reasonably competitive.

2.0 Pulverized coal power plants

There are three kinds of pulverized coal plants:

- Subcritical
- Supercritical
- Ultra-supercritical

In a PC plant, steam is admitted to the steam turbine at 1000° F and 2400 psi for subcritical and 3500 psi for supercritical [1]. (The water critical temperature and pressure are 705 ºF (374 ºC) and 3210psi (217.7 atm), respectively. When temperature exceeds 705 ºF, and pressure are above these values, water can exist only in the gaseous phase [2].) The pulverized coal is burned in a steam generator constructed of membrane waterwalls and tube bundles which absorb the radiant heat of combustion producing steam that is fed into a steam turbine generator [3]. The steam expands in the turbine, and this expansion work drives the turbine and generator to produce electricity. The expanded steam is condensed to water in the condenser and then returned to the steam generator (or boiler).

Flue-gas from the combustion of the coal in the steam generator is passed through an electrostatic precipitator to remove particulates. The flue-gas then passes through a flue-gas desulfurization (FGD) unit (or scrubber[1]), to remove SO_2 from the flue-gas,

[1] Regarding the air pollution control devices for removing SO2 from coal-fired power plant stacks, the two most common are referred to as wet and dry. In wet processes, alkaline scrubbing liquor is utilized to remove the SO2 from the flue gas, and a wet slurry waste or by-product is produced. Wet scrubber technologies include limestone forced oxidation, limestone inhibited oxidation, lime, magnesium-enhanced lime, and seawater processes. These technologies are available to coal steam units that combust bituminous coal with 2.5% or higher sulfur by weight. In dry processes, a dry sorbent is injected or sprayed to react with and neutralize the pollutant, forming a dry waste material. Dry scrubber technologies include lime spray drying, duct sorbent injection, furnace sorbent injection, and circulating fluidized bed. These technologies are available to coal steam units that combust bituminous, subbituminous, and lignite coal with less than 2.5% sulfur by weight. In addition, selective catalytic reduction is used to reduce NO_X.

achieved by mixing the flue-gas with limestone or lime, which reacts with SO_2 and is collected as a solid or liquid slurry. After scrubbing, the flue-gas is exhausted through a stack. The process is illustrated in Fig. 1.

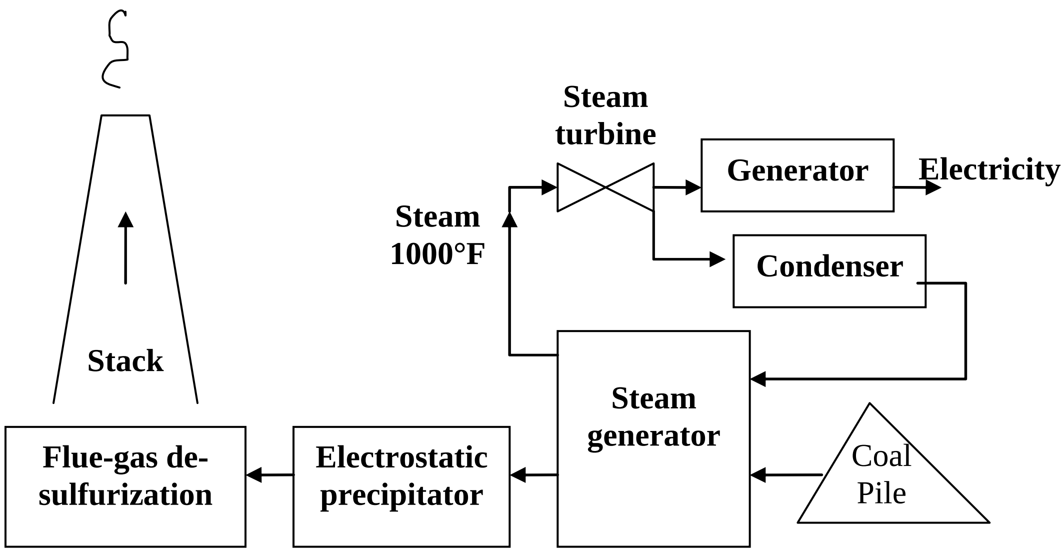


Fig. 1

A typical PC plant is shown in Fig. 2.

Fig. 2: Pulverized Coal Power Plant

Sub critical systems have thermal efficiencies of 32-35%. Super critical systems can have thermal efficiencies as high as 42%. Ultra-super-critical plants have efficiencies above 42%, potentially reaching levels of 50-55%. Fig. 3 illustrates the effect on efficiency of steam temperature and pressure.

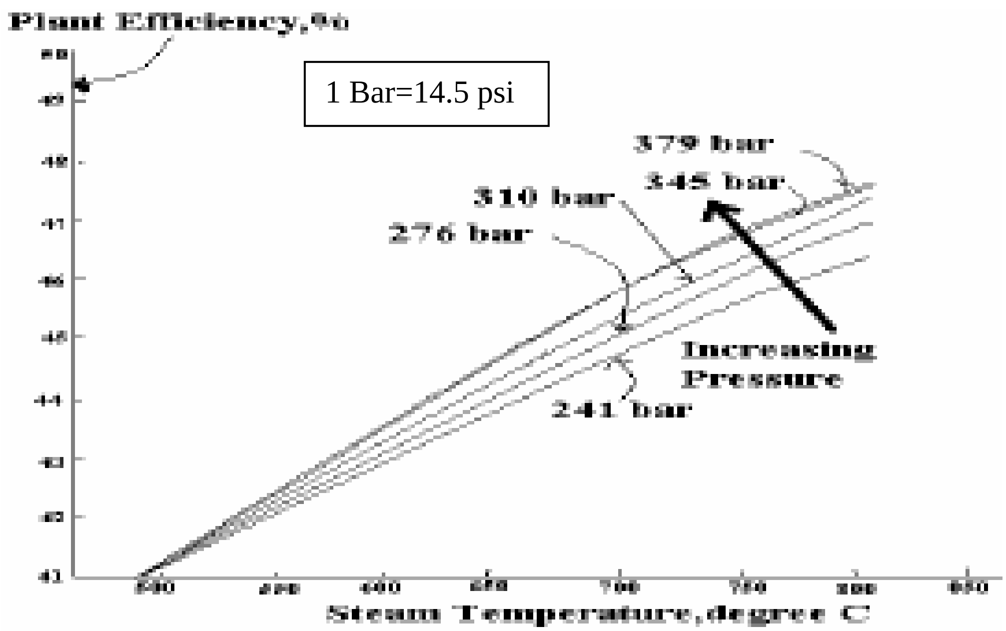


Fig. 3

The main point of this discussion is that there are three different types of PC power plants, and they have different operating temperatures and pressures and therefore different efficiencies (for the Rankine cycle, the amount of energy available for extraction by the working fluid (water) depends on the operating temperature and pressure of the fluid). The table below summarizes.

PC Plant type	Temp	Pressure	Efficiency
Subcritical	1000 ºF	2400 PSI	32-35%
Supercritical	1000 ºF	3500 PSI	38-42%
Ultra-supercritical	1112 ºF	4350 PSI	42-55%

Performance	Subcritical	PC/Supercritical	PC/Ultra-supercritical
Heat Rate Btu/kWe-h	9950	8870	7880
Gen. Efficiency (HHV)	34.3%	38.5%	43.3%
Coal use (10^6t/y)	1.548	1.378	1.221
CO_2 emitted (10^6t/y)	3.47	3.09	2.74
CO_2 emitted (g/kWe-h)	931	830	738

Assumptions: 500 MW net plant output ; Illinois #6 coal ; 85% Capacity Factor

Operating Characteristics of Three Types of PC Plants [4]

We may also observe from the below table that investment costs for subcritical and supercritical are about the same.

As of this writing, there is not an ultra-supercritical coal plant in the United States, but AEP is planning to build one in Arkansas [5]. I have not been able to find any cost-data on ultra-supercritical plants.

	Integrated Gasification Combined Cycle						Pulverized Coal Boiler				NGCC	
	GEE		CoP		Shell		PC Subcritical		PC Supercritical		Advanced F Class	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
CO_2 Capture	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes
Gross Power Output (kW$_e$)	770,350	744,960	742,510	693,840	748,020	693,555	583,315	679,923	580,260	663,445	570,200	520,090
Auxiliary Power Requirement (kW$_e$)	130,100	189,285	119,140	175,600	112,170	176,420	32,870	130,310	30,110	117,450	9,840	38,200
Net Power Output (kW$_e$)	640,250	555,675	623,370	518,240	635,850	517,135	550,445	549,613	550,150	545,995	560,360	481,890
Coal Flowrate (lb/hr)	489,634	500,379	463,889	477,855	452,620	473,176	437,699	646,589	411,282	586,627	N/A	N/A
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	165,182	165,182
HHV Thermal Input (kW$_{th}$)	1,674,044	1,710,780	1,586,023	1,633,771	1,547,493	1,617,772	1,496,479	2,210,668	1,406,161	2,005,660	1,103,363	1,103,363
Net Plant HHV Efficiency (%)	38.2%	32.5%	39.3%	31.7%	41.1%	32.0%	36.8%	24.9%	39.1%	27.2%	50.8%	43.7%
Net Plant HHV Heat Rate (Btu/kW-hr)	8,922	10,505	8,681	10,757	8,304	10,674	9,276	13,724	8,721	12,534	6,719	7,813
Raw Water Usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563	6,212	12,187	5,441	10,444	2,511	3,901
Total Plant Cost ($ x 1,000)	1,160,919	1,328,209	1,080,166	1,259,883	1,256,810	1,379,524	852,612	1,591,277	866,391	1,567,073	310,710	564,628
Total Plant Cost ($/kW)	1,813	2,390	1,733	2,431	1,977	2,668	1,549	2,895	1,575	2,870	554	1,172
LCOE (mills/kWh)[1]	78.0	102.9	75.3	105.7	80.5	110.4	64.0	118.8	63.3	114.8	68.4	97.4
CO_2 Emissions (lb/hr)	1,123,781	114,476	1,078,144	131,328	1,054,221	103,041	1,038,110	132,975	973,370	138,681	446,339	44,634
CO_2 Emissions (tons/year) @ CF[1]	3,937,728	401,124	3,777,815	460,175	3,693,990	361,056	3,864,884	569,524	3,631,301	516,310	1,661,720	166,172
CO_2 Emissions (tonnes/year) @ CF[1]	3,572,267	363,896	3,427,196	417,466	3,351,151	327,546	3,506,185	516,667	3,294,280	468,392	1,507,496	150,750
CO_2 Emissions (lb/MMBtu)	197	19.6	199	23.6	200	18.7	203	20.3	203	20.3	119	11.9
CO_2 Emissions (lb/MWh)[2]	1,459	154	1,452	189	1,409	149	1,780	225	1,681	209	783	85.8
CO_2 Emissions (lb/MWh)[3]	1,755	206	1,730	253	1,658	199	1,886	278	1,773	254	797	93
SO_2 Emissions (lb/hr)	73	56	68	48	55	58	433	Negligible	407	Negligible	Negligible	Negligible
SO_2 Emissions (tons/year) @ CF[1]	254	196	237	167	194	204	1,613	Negligible	1,514	Negligible	Negligible	Negligible
SO_2 Emissions (tonnes/year) @ CF[1]	231	178	215	151	176	185	1,463	Negligible	1,373	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MMBtu)	0.0127	0.0096	0.0125	0.0085	0.0105	0.0105	0.0848	Negligible	0.0847	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh)[2]	0.0942	0.0751	0.0909	0.0686	0.0739	0.0837	0.7426	Negligible	0.7007	Negligible	Negligible	Negligible
NOx Emissions (lb/hr)	313	273	321	277	309	269	357	528	336	479	34	34
NOx Emissions (tons/year) @ CF[1]	1,096	955	1,126	972	1,082	944	1,331	1,966	1,250	1,784	127	127
NOx Emissions (tonnes/year) @ CF[1]	994	867	1,021	882	982	856	1,207	1,783	1,134	1,618	115	115
NOx Emissions (lb/MMBtu)	0.055	0.047	0.059	0.050	0.058	0.049	0.070	0.070	0.070	0.070	0.009	0.009
NOx Emissions (lb/MWh)[2]	0.406	0.366	0.433	0.400	0.413	0.388	0.613	0.777	0.579	0.722	0.060	0.066
PM Emissions (lb/hr)	41	41	38	40	37	39	66	98	62	89	Negligible	Negligible
PM Emissions (tons/year) @ CF[1]	142	145	135	139	131	137	247	365	232	331	Negligible	Negligible
PM Emissions (tonnes/year) @ CF[1]	129	132	122	126	119	125	224	331	211	300	Negligible	Negligible
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0130	0.0130	0.0130	0.0130	Negligible	Negligible
PM Emissions (lb/MWh)[2]	0.053	0.056	0.052	0.057	0.050	0.057	0.114	0.144	0.107	0.134	Negligible	Negligible
Hg Emissions (lb/hr)	0.0033	0.0033	0.0031	0.0032	0.0030	0.0032	0.0058	0.0086	0.0055	0.0078	Negligible	Negligible
Hg Emissions (tons/year) @ CF[1]	0.011	0.012	0.011	0.011	0.011	0.011	0.022	0.032	0.020	0.029	Negligible	Negligible
Hg Emissions (tonnes/year) @ CF[1]	0.010	0.011	0.010	0.010	0.010	0.010	0.020	0.029	0.019	0.026	Negligible	Negligible
Hg Emissions (lb/TBtu)	0.571	0.571	0.571	0.571	0.571	0.571	1.14	1.14	1.14	1.14	Negligible	Negligible
Hg Emissions (lb/MWh)[2]	4.24E-06	4.48E-06	4.16E-06	4.59E-06	4.03E-06	4.55E-06	1.00E-05	1.27E-05	9.45E-06	1.18E-05	Negligible	Negligible

[1] Capacity factor is 80% for IGCC cases and 85% for PC and NGCC cases

[2] Value is based on gross output

[3] Value is based on net output

Sub and Supercritical PC are the most mature coal burning technologies today, and we have more experience with them than any other power generation technology. It is very reliable, easy to operate and maintain, and can accommodate up to 1,300 MW. Although fuel costs are very low, these units tend to have less fuel flexibility than CFB units (see below) in that they are more sensitive to fuel characteristics, slagging, and fouling.

3.0 Fluidized bed coal plants

In fluidized bed combustion (FBC), solid fuels are suspended on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, like a bubbling fluid, provides more effective chemical reactions & heat transfer [6].

Fluidized-bed combustion evolved from efforts to find a combustion process able to control SO_2 emissions without scrubbers. The technology burns fuel at temperatures of 1400-1700° F, well below the threshold where nitrogen oxides form (at approximately 2500° F, the nitrogen and oxygen atoms in the combustion air combine to form nitrogen oxide pollutants). The mixing action of the fluidized bed brings the flue gases into contact with a sulfur-absorbing chemical, such as limestone. More than 95 percent of the SO_2 in coal can be captured inside the boiler by the sorbent [6].

There two broad classes of FBC:

- Atmospheric fluidized bed combustion (AFBC), where the boilers operate at atmospheric pressure.
- Pressurized fluidized bed combustion (PFBC), where the boilers operate at elevated pressures and produce a high-pressure gas stream at temperatures that can drive a gas turbine. Steam generated from the heat in the fluidized bed is sent to a steam turbine, creating a highly efficient combined cycle system.

The AFBC was the earliest fluidized-bed plants built and used “bubbling-bed” technology, Fig. 4 [7]. Here, a stationary fluidized bed in the boiler uses low air velocities to fluidize the material and a heat exchanger immersed in the bed to generate steam.

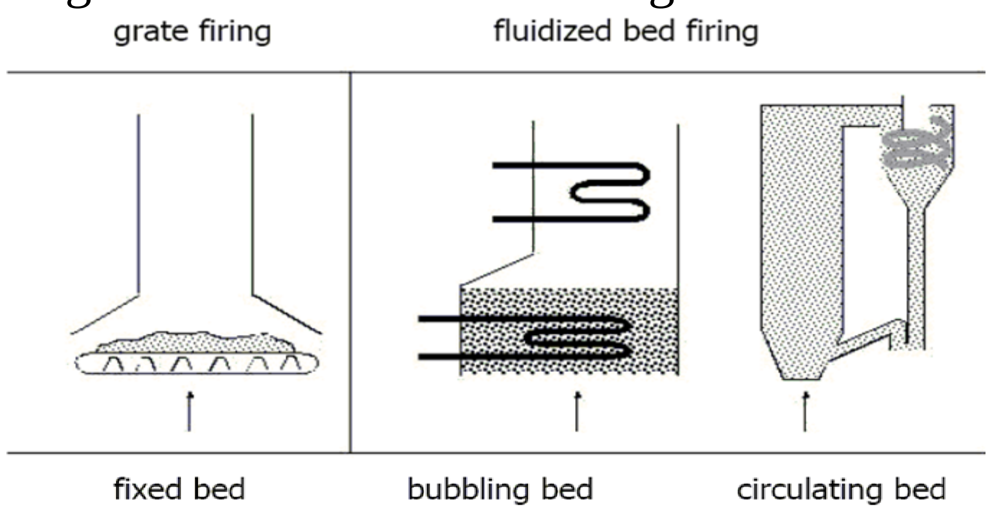


Fig. 4

PFBCs have used both bubbling bed and circulating beds, Fig. 4. In these plants, Fig. 5a [3], combustion air is introduced through the bottom of the bed material normally consisting of fuel, limestone, and ash. Heat generated from burning fuel produces steam which is fed into a steam turbine generator [3].

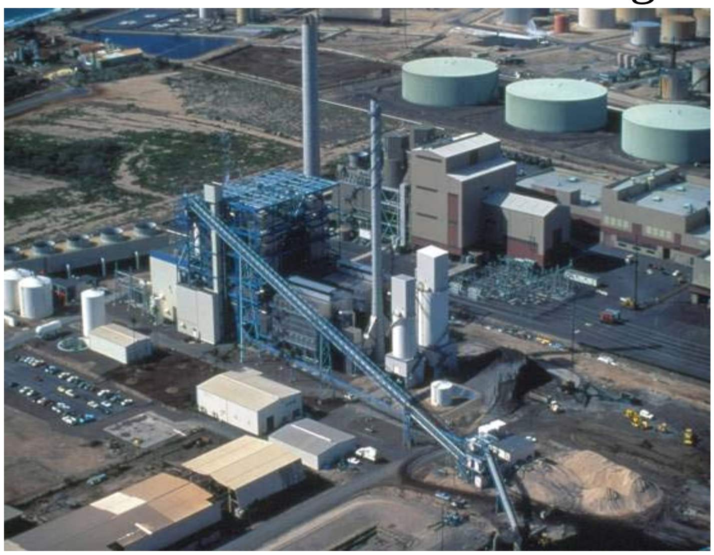


Fig. 5a: Circulating fluidized bed

This circulating fluidized bed (CFB) plant has ability to burn a wide variety of fuels and thus has much greater fuel diversity than PC. It is reliable and easy to operate and maintain because low combustion temperatures tend to minimize slagging and fouling tendencies. Yet, to date, no units larger than 300 MW have been built, their operations and maintenance costs are slightly higher than for PC units, and they are less suited for numerous startups and cycling than PC units. In addition, they are typically a little less efficient than PC plants.

A related technology is the Pressurized Fluidized Bed Combustion Combined Cycle (APFBC) plant [8], which combines the benefits of FBC and those of combined cycle units. APFBC uses a circulating pressurized fluidized bed combustor (PFBC) with a fluid bed heat exchanger to develop hot vitiated air for the gas turbine's topping combustor and steam for the steam bottoming cycle, and a carbonizer to produce hot fuel gas for the gas turbine's topping combustor. This provides high combined cycle energy efficiency levels on coal. Figure 5b illustrates a PFBC [9].

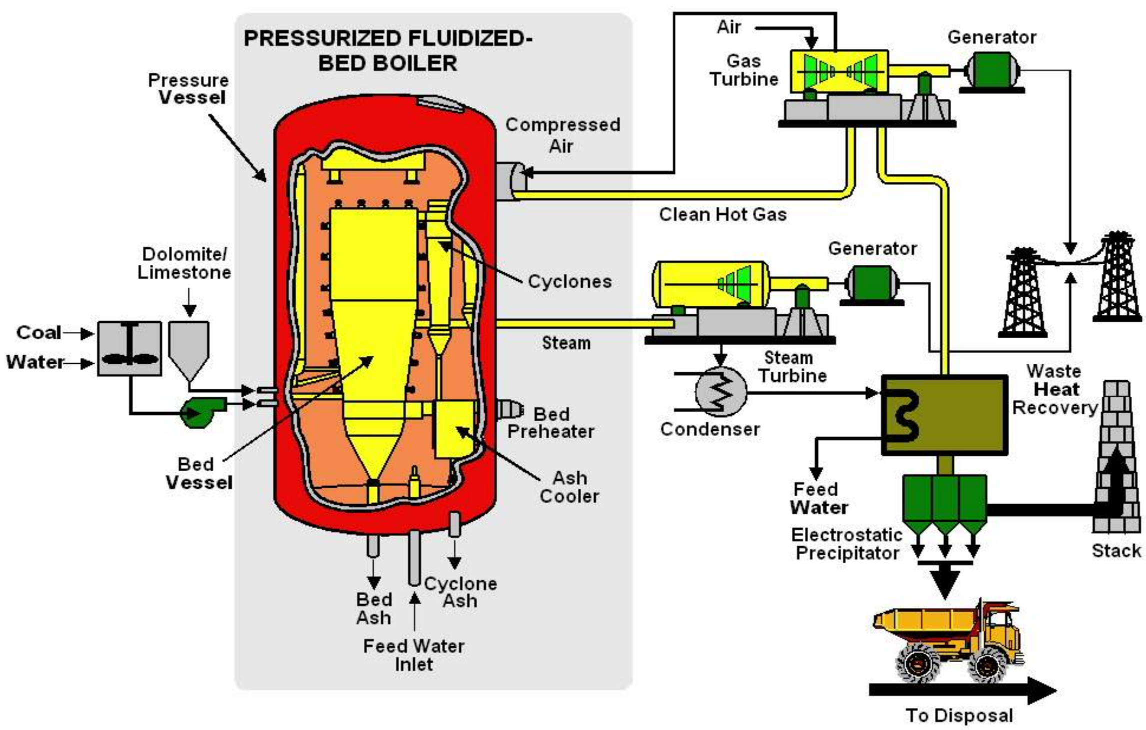


Fig. 5b

Table 1 provides emissions removal rates and other data for several PFBC plants around the world [9].

Table 1

PLANT	Location	Output MWe	Coal Type	Commission Date	SO_2 emission % removal	NOx emission mg/MJ
Vartan	Sweden	135	Bituminous	1990	94-99	10-50
Tidd	Ohio	70	Bituminous	1991	91-93	75-90
Escatron	Spain	79	high sulfur black lignite	1990	90	75-90
Wakamatsu	Japan	71	Bituminous	1994	90-95	15-40
Tomato	Japan	85	Coal	1995		
Trebovice	Czech Republic	70	Hard coal	1996		
Karita	Japan	350	Hard coal	1999		
Osaki	Japan	250		1999		
Cottbus	Germany	71	Brown coal	1999		

Fig. 6a compares LCOE for coal-fired power plants [9] in cents/kWhr.

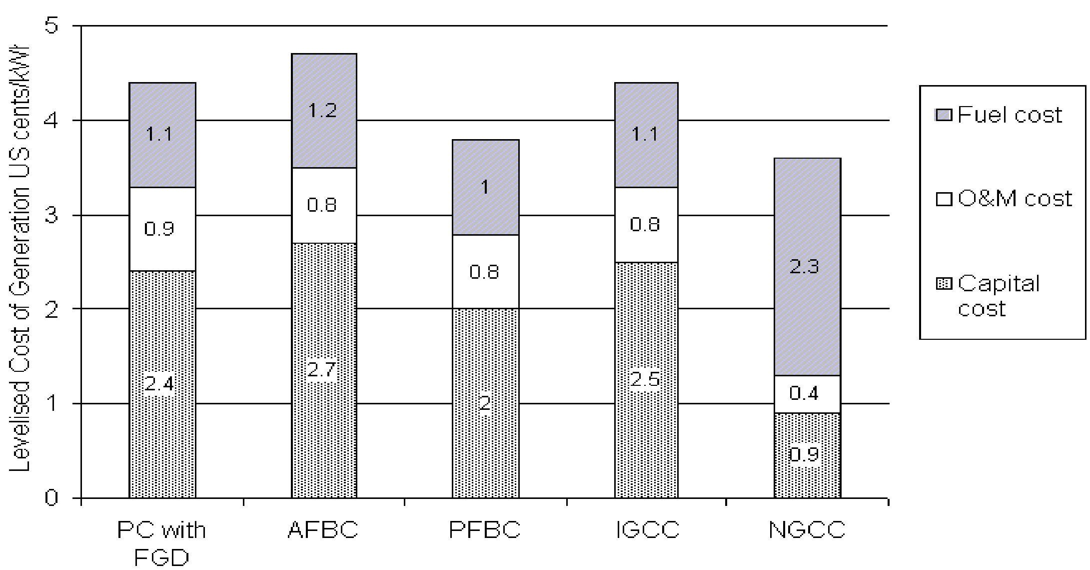


Fig. 6a

4.0 CO_2 Capture and Sequestration for coal

Any coal-fired generation technology will require CO_2 capture and sequestration in order to significantly reduce its CO_2 emissions.

There are two ways to perform CO_2 capture for PC or for CFB plants: post-combustion capture and oxygen based combustion. A third way is called pre-combustion and involves IGCC, to be discussed in Section 5 below. The three ways are illustrated in Fig. 6b [10].

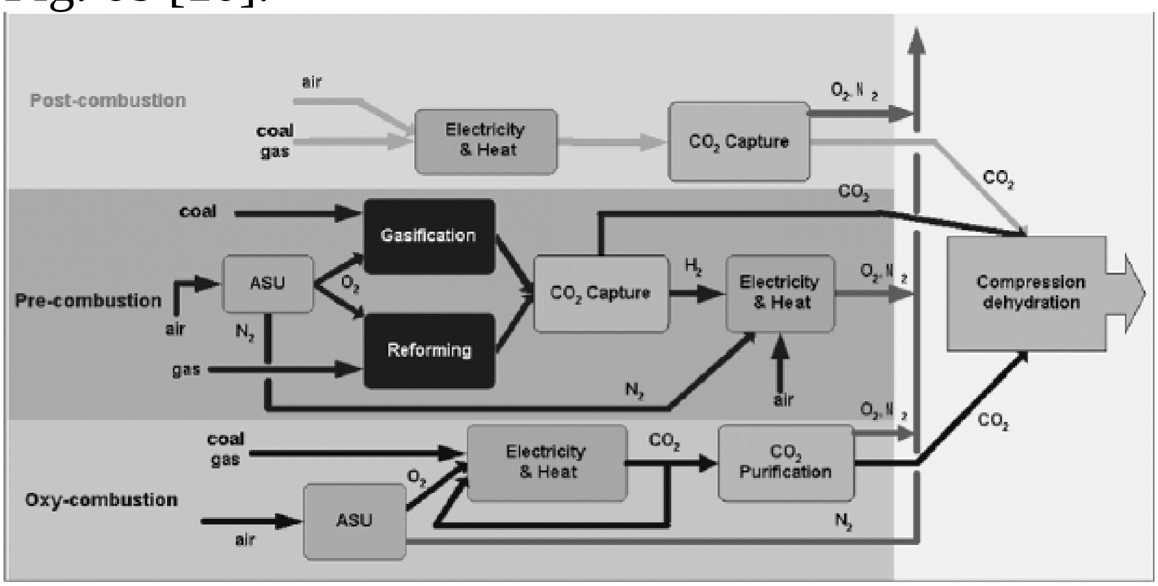


Fig. 6b [10]

Post-combustion refers to capturing CO_2 from the flue (exhaust) gases after a fuel has been combusted in air. It comprises an absorber where CO2 is captured using a chemical solvent like an amine and a regenerator where the captured CO2 is released from the solvent. Amines are ammonia derivatives and include aqueous monoethanolamine (MEA), diglycolamine (DGA), diethanolamine (DEA), diisopropanolamine (DIPA) and methyldiethanolamine (MDEA).

Oxycombustion (or O_2-fired combustion) is an approach where a hydrocarbon fuel is combusted in a mixture of oxygen and carbon dioxide, rather than air, to produce an exhaust mixture of CO_2 and water vapor [11]. With air nitrogen eliminated, a CO_2-water vapor rich flue gas is generated. After partial removal of the water vapor, a portion of the flue gas is re-circulated back to the boiler to control the combustion temperature and the balance of the CO_2 is processed for pipeline transport. This oxygen-fired combustion process eliminates the need for the CO_2 removal/separation process and, despite the expense and power consumption of air separation, reduces the cost of CO_2 capture [11].

The products of combustion are thus only CO_2 and water vapor. The water vapor is readily condensed, yielding a nearly-pure CO_2 stream ready for sequestration. The CO_2 effluent is compressed at high pressure (greater than 2000 psia) and is piped from the plant to be sequestered in geologic formations such as depleted oil and gas reservoirs [11].

Oxycombustion can be adapted to new power plants or retrofit applications. In Fig. 7, the levelized cost of energy (including fixed costs, O&M, and fuel costs) are compared for an air-fired plant with no capture, a plant with post-combustion capture, an IGCC with pre-combustion capture, and one with oxycombustion [11].

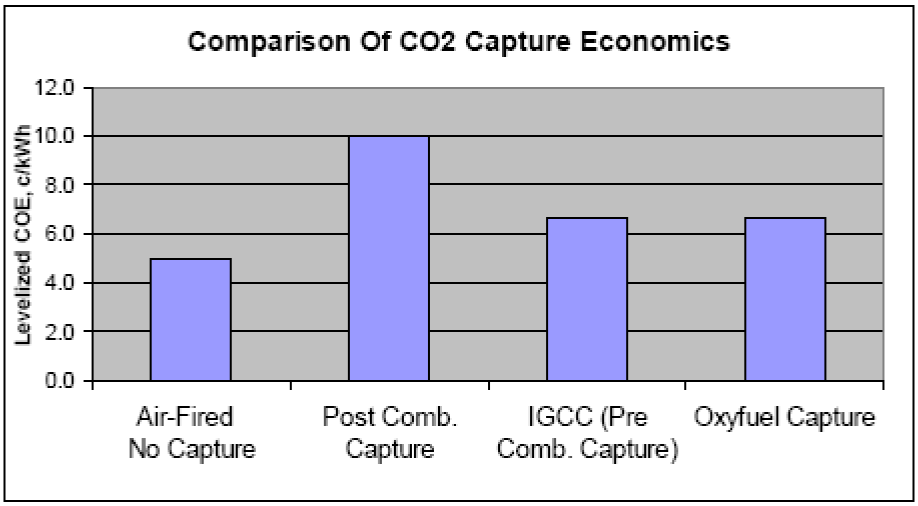


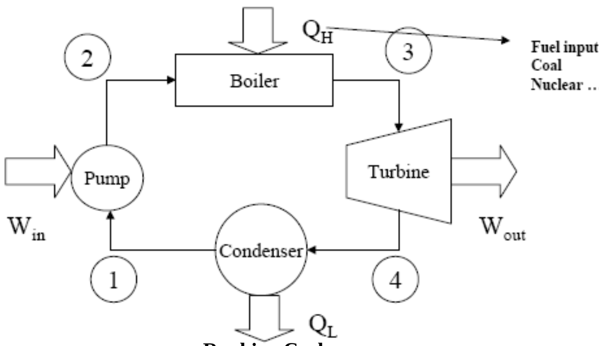
Fig. 7

5.0 Simple Cycle Combustion turbines

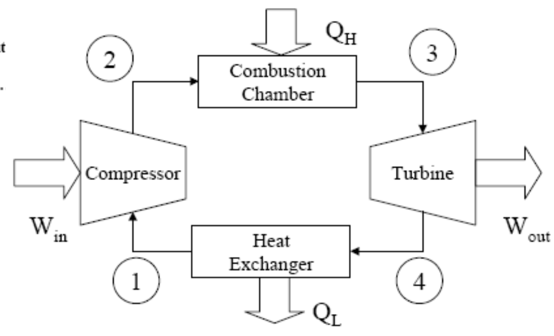
Simple cycle combustion turbines (CTs), Fig. 8, [3] generate power by compressing and heating ambient air and then expanding those hot gases through a turbine which turns an electric generator. They are also referred to as a "gas turbine" and identical to jet engines in theory of operation. CTs, a mature technology, have low capital cost, short design and installation schedules, rapid startup times, and high reliability. On the other hand, they have high operations and maintenance costs when compared to combined cycle units and are therefore only used for peaking operation. Sizes are typically less than 300 MW.

Fig. 8: CT Power Plant

Whereas steam-fired power plants operate on the Rankine thermodynamic cycle, CTs operate on the Brayton cycle. These cycles are illustrated in Fig. 9a [12]. Note that in the Rankine cycle, the working fluid (water) continuously changes from liquid to gaseous states, whereas in the Brayton cycle, the working fluid is always in the gaseous state.



Rankine Cycle



Brayton Cycle

1-2: Liquid water pumped to a higher pressure adiabatically (constant heat)
2-3: Heat is added by boiling the water (constant pressure)
3-4: High pressure steam drives the turbine adiabatically (constant heat)
4-1: Steam is condensed to liquid water (constant temp, constant pressure)

1-2: Air is compressed adiabatically (constant heat)
2-3: Heat is added by burning fuel (constant pressure)
3-4: High pressure air drives a turbine (constant heat)
4-1: Air exhausted from the turbine is cooled to state 1 (constant pressure)

Fig. 9a

It should be recognized that gas turbines typically operate on an open cycle, as illustrated in the left-hand-side of Fig. 9b, but under so-called air-standard assumptions, they are modeled thermodynamically as shown on the right-hand-side of Fig. 9b, where the combustion process is replaced by a heat-exchange process [13].

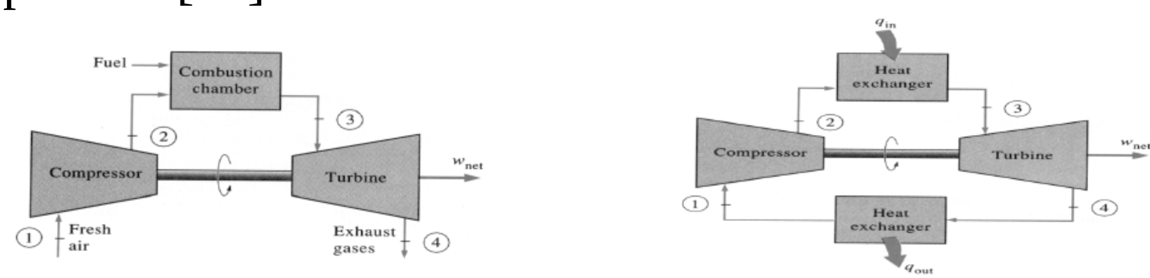


Fig. 9b

6.0 Natural Gas Combined Cycle power plants

Combined cycle combustion turbines [3], Fig. 10, generate power by compressing and heating ambient air and then expanding those hot gases through a turbine which turns an electric generator. In addition, heat from the hot gases of combustion is captured in a heat recovery steam generator (HRSG) producing steam which is passed through a steam turbine generator. NGCC units have low emissions and significantly higher efficiency than CTs. But their capital cost is higher than CTs. Compared to standard baseload plants, they are subject to the volatility of natural gas prices. Their O&M costs are higher than PC plants.

Fig. 10: NGCC Power Plant

Combined cycle plants are so named because they combine the Rankine & Brayton cycles, as shown in Fig. 11, where we see what was previously wasted heat from the Brayton cycle (the gas turbine) is now being used to produce steam in a Rankine cycle.

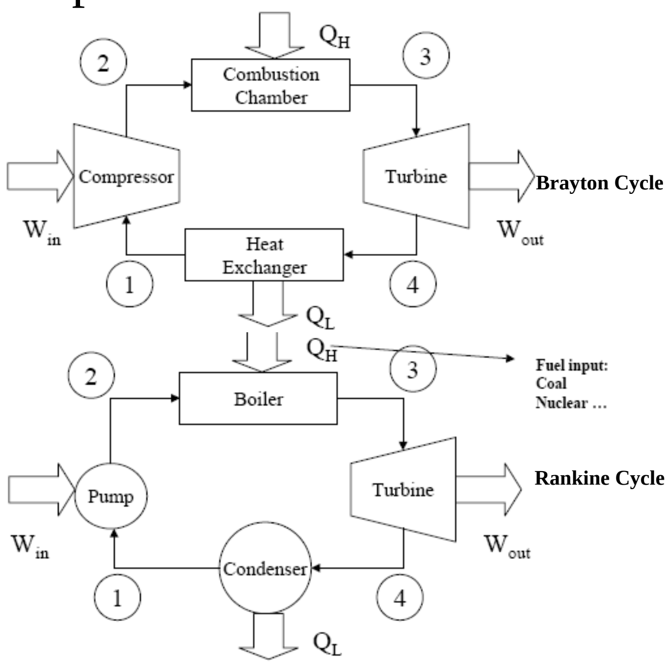


Fig. 11

7.0 Integrated gasification combined cycle, IGCC

Figure 12 shows the Wabash River, Indiana IGCC.

Fig. 12

Figs. 13a [14] and 13b [15] illustrate an integrated gasification combined cycle (IGCC) unit. Here,

- Coal is fed into a high-temperature pressurized container called a gasifier, along with steam and a limited amount of oxygen.
- The combination of heat, pressure, and steam breaks down the coal and creates chemical reactions that produce synthesis gas (syngas) comprised of H_2, CO.
- The gas is cooled and undesirable components, CO_2, SO_2, are captured via chemical absorption. This is an advantage in that this pre-combustion process is very inexpensive in comparison to the post-combustion processes used in pulverized coal plants.

The syngas can be used to drive a combustion turbine in a combined cycle process, and/or it can be further processed to separate the hydrogen for use as an energy source for stationary or mobile applications.

Gasification systems can be coupled with fuel cell systems for future applications. Fuel cells convert hydrogen gas to electricity (and heat) using an electro-chemical process. There are very little air emissions and the primary exhaust is water vapor. If the costs of fuel cells and biomass gasifiers decrease, these systems are expected to proliferate.

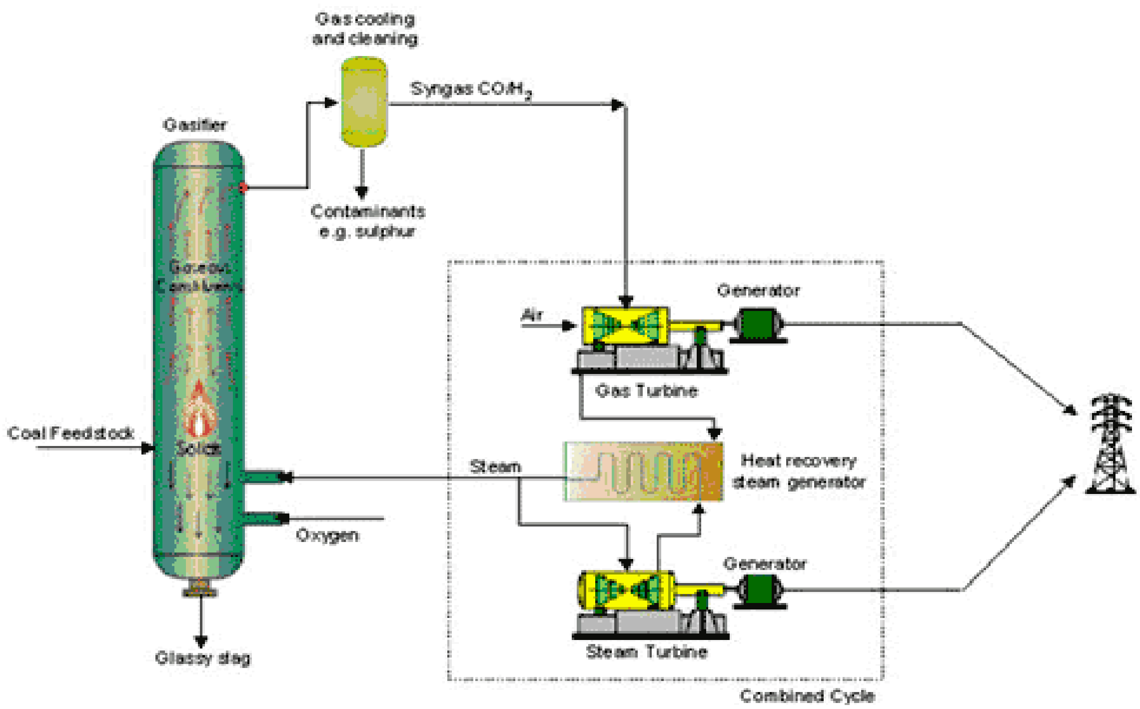


Fig. 13a

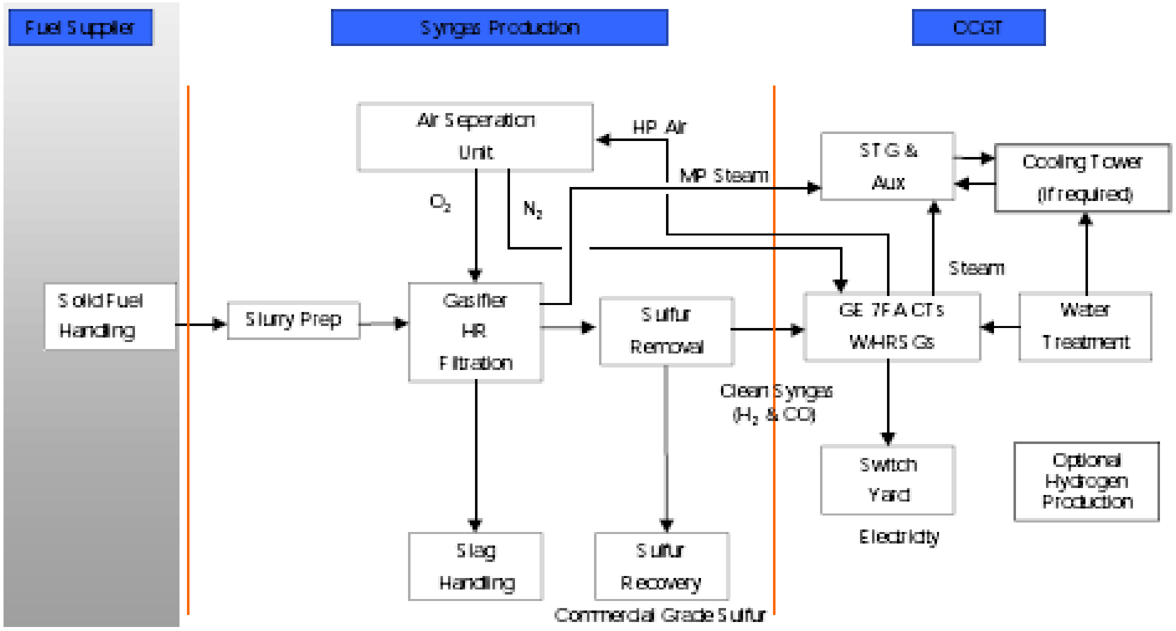


Fig. 13b

There are three kinds of oxygen gasifiers: moving bed gasifiers; fluidized bed gasifiers; and entrained bed gasifiers. EPRI has found that single stage entrained gasifiers were found to have the best features. One of those features is that they are best for producing syngas for Fischer-Tropsch synthesis.

The Fischer-Tropsch process is a reaction where syngas is converted into liquid hydrocarbons. The principal purpose of this process is to produce a synthetic petroleum substitute for use as synthetic lubrication oil or as synthetic fuel (synfuel). This synfuel runs trucks, cars, and some aircraft engines.

IGCCs are available today, as indicated in the summary of GE-IGCC's penetration, Table 2.

Table 2: GE-IGCC Penetration

Customer	C.O. Date	MW	Application	Gasifier
SCE Cool Water - USA	**1984**	**120**	**Power/Coal**	**Texaco - O_2**
LGTI - USA	1987	160	Cogen/Coal	Destec - O_2
Demkolec - Netherlands	1994	250	Power/Coal	Shell - O_2
PSI/Destec - USA	**1996**	**260**	**Repower/Coal**	**Destec - O_2**
Tampa Electric - USA	**1996**	**260**	**Power/Coal**	**Texaco - O_2**
Texaco El Dorado - USA	**1996**	**40**	**Cogen/Pet Coke**	**Texaco - O_2**
SUV - Czech.	**1996**	**350**	**Cogen/Coal**	**ZUV - O_2**
Schwarze Pumpe - Germany	**1996**	**40**	**Power/Methanol/Lignite**	**Noell - O_2**
Shell Pernis - Netherlands	**1997**	**120**	**Cogen/H_2/Oil**	**Shell - O_2**
Puertollano - Spain	1998	320	Power/Coal/Pet Coke	Prenflow - O_2
Sierra Pacific - USA	**1998**	**100**	**Power/Coal**	**KRW - Air**
ISAB - Italy	1999	500	Power/H_2/Oil	Texaco - O_2
API - Italy	2000	250	Power/H_2/Oil	Texaco - O_2
MOTIVA - Delaware	**2000**	**240**	**Repower/Pet Coke**	**Texaco - O_2**
Sarlux/Enron - Italy	**2000**	**550**	**Cogen/H_2/Oil**	**Texaco - O_2**
EXXON – Singapore	**2000**	**180**	**Cogen/H_2/Oil**	**Texaco - O_2**
Nihon Sekiyu - Japan	2004	350	Power/Oil	Texaco - O_2
Bio Electrica – Italy	**2006**	**12**	**Power/Biomass**	**Lurgi – Air**
ENI-San Nazzaro, Italy	2005	150	Power/Oil Cogen	Shell
IOC Paradip	**2006**	**180**	**Power/Pet Coke**	**Shell O_2**
Global-Kylkima, OH	**2006**	**1000**	**Power/Coal/RDF**	**BGL - O_2**
EDF - Total	**2006**	**400**	**Power/H_2/Cogen/Oil**	**Texaco - O_2**
Texaco/TVA	**2006**	**800**	**Power/Coal**	**Texaco - O_2**
PIEMSA	**2006**	**800**	**Power/H_2/Oil**	**Texaco - O_2**
TPS/Lake Charles	**2006**	**1000**	**Power/H_2/Oil**	**Texaco - O_2**
		8432		

- Projects in operation, under construction or announced
- **Bold: GE Gas Turbines**

IGCC's compare favorably with other coal-fired generation technologies, as indicated in Table 3a. The one attribute that is not favorable to IGCCs is availability, which is just below that of CFB and PC.

Table 3a: Comparison of IGCC with CFB and PC

700-800 MW Plant in Illinois	CFB – 700MW NET	PC – 720 MW NET	IGCC – 810 MW NET
Unit Size (MW)	3 x 266	1 x 800	1 x 900
Net Plant Output (MW)	700	720	810
Installed EPC Cost ($ per kW)	$1520	$1380	$1300
Heat Rate (Btu/kWh – HHV) Illinois Coal	9,900	9,600	8,500
O&M Cost w/Major Maint ($MM per yr)	$53	$46	$56
Availability	93%	93%	92%
Power Price (2002 $/MWh)	$42.49	$38.17	$36.62
Proposed EPA Limits:			
NO_x 0.016 (lbs per MM Btu)	0.20	0.06	0.036 (9 ppmwb SCR)
SO_2 0.040 (lbs per MM Btu)	0.70	0.22	0.046 (98.92%)
PM_{10} 0.006 (lbs per MM Btu)	0.015	0.018	0.01
Hg 0.200 (lbs per MM Btu)	Expensive	Expensive	0.13 (95%)
CO_2 Capture	Expensive	Expensive	Low Cost

IGCCs may also be driven by biomass (wood residues, agricultural waste, energy crops, and municipal waster (garbage)). Biomass-IGCC (BIGCC) and Natural Gas Combined Cycle (NGCC) have potential to reduce GHG over that of pulverized coal setups by 94% and 41%, respectively [16]. Even with CO_2 sequestration in typical coal or NGCC setups, a BIGCC plant without CO_2 sequestration has better GHG reduction. The cost of electricity from BIGCC at 600 MW scale will be 5.5¢/kWh; PC and NGCC both with CO_2 sequestration will be 7.3¢/kWh & 7.5¢/kWh, respectively.

Other data comparing IGCCs and traditional plants is in [10]. Fig. 13c shows results from this study comparing efficiency, investment cost, and LCOE.

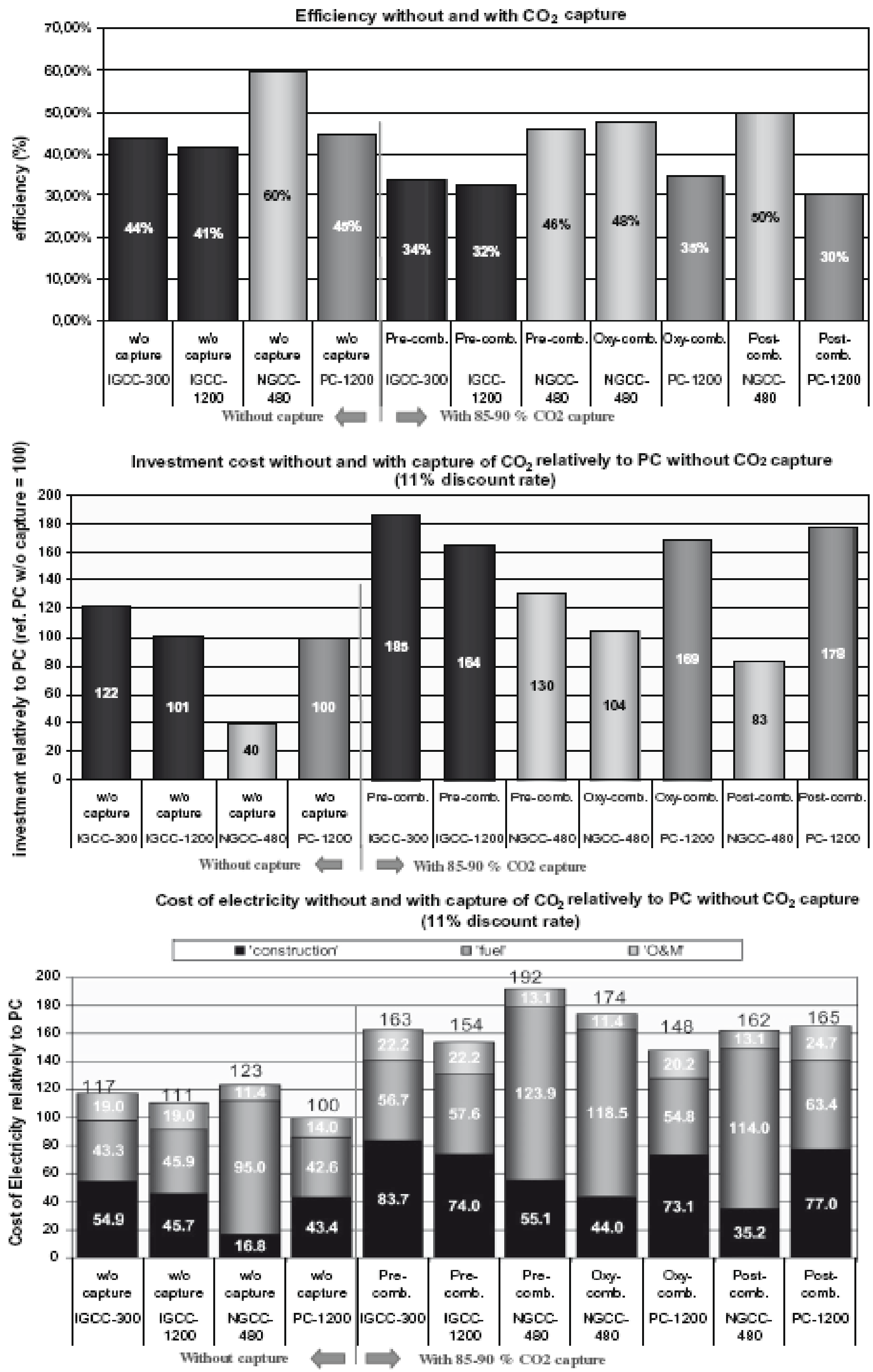

Efficiency without and with CO2 capture
efficiency (%)
70,00% 60,00% 50,00% 40,00% 30,00% 20,00% 10,00% 0,00%
44% 41% 60% 45% 34% 32% 46% 48% 35% 50% 30%
w/o capture IGCC-300
w/o capture IGCC-1200
w/o capture NGCC-480
w/o capture PC-1200
Pre-comb. IGCC-300
Pre-comb. IGCC-1200
Pre-comb. NGCC-480
Oxy-comb. NGCC-480
Oxy-comb. PC-1200
Post-comb. NGCC-480
Post-comb. PC-1200
Without capture
With 85-90 % CO2 capture
Investment cost without and with capture of CO2 relatively to PC without CO2 capture (11% discount rate)
investment relatively to PC (ref. PC w/o capture = 100)
200 180 160 140 120 100 80 60 40 20 0
122 101 40 100 185 164 130 104 169 83 178
w/o capture IGCC-300
w/o capture IGCC-1200
w/o capture NGCC-480
w/o capture PC-1200
Pre-comb. IGCC-300
Pre-comb. IGCC-1200
Pre-comb. NGCC-480
Oxy-comb. NGCC-480
Oxy-comb. PC-1200
Post-comb. NGCC-480
Post-comb. PC-1200
Without capture
With 85-90 % CO2 capture
Cost of electricity without and with capture of CO2 relatively to PC without CO2 capture (11% discount rate)
'construction' 'fuel' 'O&M'
Cost of Electricity relatively to PC
200 180 160 140 120 100 80 60 40 20 0
117 111 123 100 163 154 192 174 148 162 165
19.0 19.0 11.4 14.0 22.2 22.2 13.1 11.4 20.2 13.1 24.7
43.3 45.9 95.0 42.6 56.7 57.6 123.9 118.5 54.8 114.0 63.4
54.9 45.7 16.8 43.4 83.7 74.0 55.1 44.0 73.1 35.2 77.0
w/o capture IGCC-300
w/o capture IGCC-1200
w/o capture NGCC-480
w/o capture PC-1200
Pre-comb. IGCC-300
Pre-comb. IGCC-1200
Pre-comb. NGCC-480
Oxy-comb. NGCC-480
Oxy-comb. PC-1200
Post-comb. NGCC-480
Post-comb. PC-1200
Without capture
With 85-90 % CO2 capture

Fig. 13c

8.0 Nuclear power plants

New nuclear power capacity has been dormant since the last nuclear power plant to come on-line (1996, Watts Bar, Tennessee). Fig. 13d illustrates the situation.

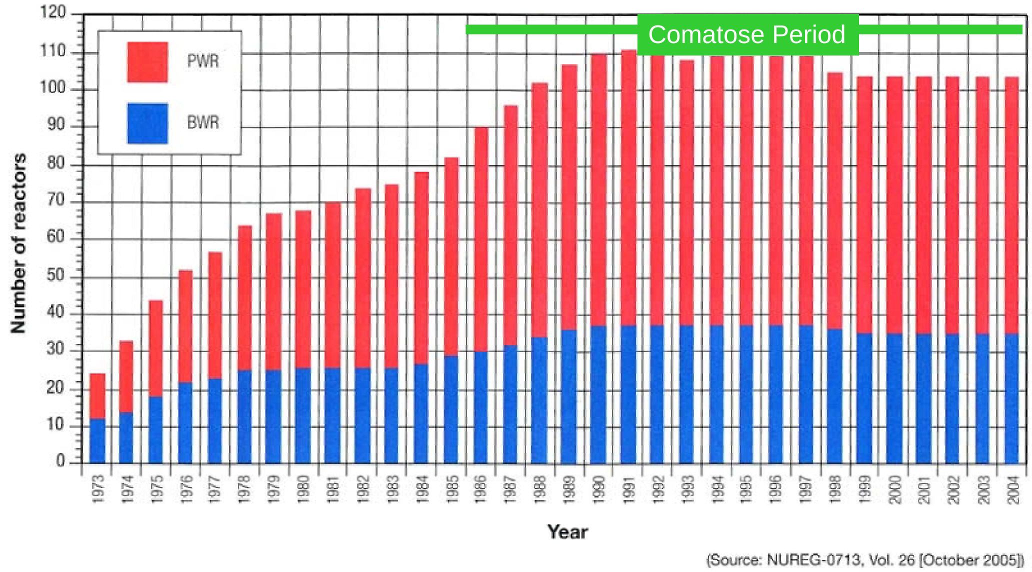


Fig. 13d: Number of US Operating Reactors ‘73-‘04

If we assume a 50 year life on these plants, and noting that over half the plants were operating by 1978, all almost all by 1990, we will lose half of this resource by 2028 and all of it by 2038, if no additional nuclear plants are built.

We will see that things could be changing, but before that, we will review the technology itself.

As indicated in Fig. 14, there are 2 kinds of nuclear power plants in the United States: boiling water reactors (BWR) & pressurized water reactors (PWR). Both are referred to as “light-water reactors,” because they use ordinary water as the moderator between fuel rods. A moderator is necessary to slow down released neutrons released from fission to a speed or energy to cause further fission & sustain the reaction.

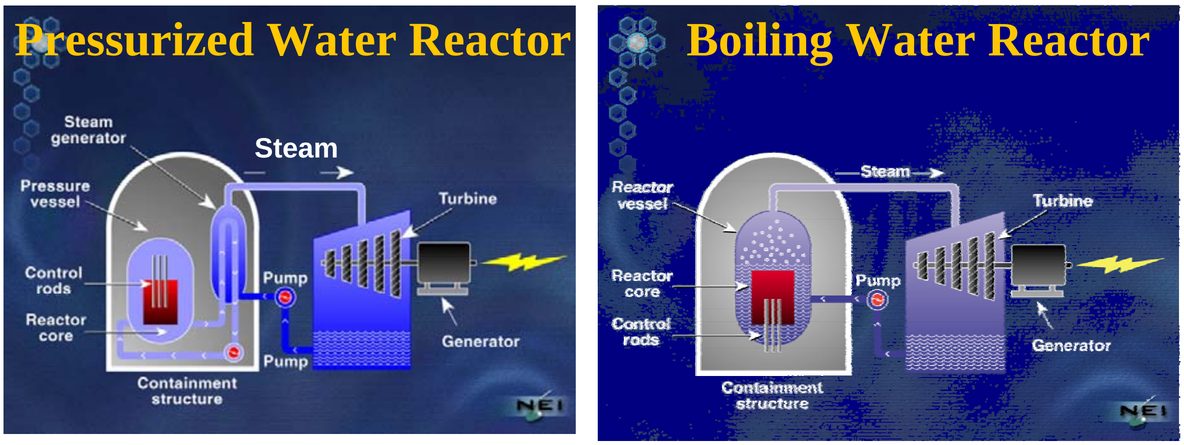


Fig. 14

In the PWR, light water is heated by the nuclear fuel, but is kept under pressure in the pressure vessel, so it will not boil. The water inside the pressure vessel is piped through separate tubing to a steam generator. The steam generator acts like a heat exchanger. There is a second supply of water inside the steam generator. Heated by the water from the pressure vessel, it boils to make steam for the turbine. PWR reactor sizes range from 600 to 1,200 MW and account for 57% of the world’s power reactors. Most of the US nuclear plants, such as Fig. 15a, are PWR.

Fig. 15a: Diablo Canyon Nuclear Power Plant

Inside a BWR, heat from the chain reaction boils the water and turns it to steam. A BWR uses only one moderator/cooling loop. The steam is piped from the reactor vessel directly to the turbine which is then used to drive the turbine. The BWR is available in 600 to 1,400 MW configurations and accounts for 21% of the world's power reactors [17]. With 57% PWR, this leaves 22%, of which most are Pressurized Heavy Water Reactors (PHWR) otherwise known as CANDU[2], a similar Russian design called Reaktor Bolshoy Moschnosti Kanalniy (RBMK), the British Gas Cooled Reactor (GCR) and Advanced Gas Cooled Reactor (AGR), and a few others.

[2] Reactors used in Canada use heavy water as the moderator in their reactors. Since the deuterium in heavy water is slightly more effective in slowing down the neutrons from the fission reactions, the uranium fuel needs no enrichment and can be used as mined. The Canadian style reactors are commonly called CANDU reactors.

A BWR is a simpler design than a PWR, but it exposes steam from the containment structure to the external world. In contrast, the PWR maintains primary water isolated in the containment structure and is therefore considered to be a safer design.

A summary of different types of nuclear power plants is given in Table 4 below.

Table 4: Nuclear power plants in commercial operation

Reactor type	Main Countries	Number	GWe	Fuel	Coolant	Moderator
Pressurised Water Reactor (PWR)	US, France, Japan, Russia	264	250.5	enriched UO_2	water	water
Boiling Water Reactor (BWR)	US, Japan, Sweden	94	86.4	enriched UO_2	water	water
Pressurised Heavy Water Reactor 'CANDU' (PHWR)	Canada	43	23.6	natural UO_2	heavy water	heavy water
Gas-cooled Reactor (AGR & Magnox)	UK	18	10.8	natural U (metal), enriched UO_2	CO_2	graphite
Light Water Graphite Reactor (RBMK)	Russia	12	12.3	enriched UO_2	water	graphite
Fast Neutron Reactor (FBR)	Japan, France, Russia	4	1.0	PuO_2 and UO_2	liquid sodium	none
Other	Russia	4	0.05	enriched UO_2	water	graphite
	TOTAL	439	384.6			

GWe = capacity in thousands of megawatts (gross)

Both BWR’s and PWR’s have high capital costs and long lead time to construct plants. The uranium fuel must be *enriched* to run in these reactors, significantly adding to fuel costs. The enrichment process increases the percentage of U-235 concentrations to above 4% (natural deposits of uranium contain 99.3% U-238, which is not fissionable). There are about 100 research-grade reactors in the world which use highly-enriched (90%) uranium which is a weapons-grade level and thus causes significant concern of theft.

They produce no emissions but do produce 2 kinds of nuclear waste: Low level and high level waste. Both must be stored in underground facilities until fully diminished.

- Low-level waste has a 30-year cool down period; it includes radioactively contaminated protective clothing, tools, filters, rags, medical tubes, and many other items. There are three low-level waste sites in the US: South Carolina, Utah, and Washington State.
- High-level waste has a 100-1000+ year cool down period; this is used nuclear reactor fuel. It can exist in two forms: spent reactor fuel when it is accepted for disposal or waste materials remaining after spent fuel is reprocessed. Until a permanent disposal repository for spent nuclear fuel is built,

licensees must safely store this fuel at their reactors.

- On June 3, 2008, the DOE submitted a license application to the NRC, seeking authorization to construct a deep geologic repository for disposal of high-level radioactive waste at Yucca Mountain, Nevada.
- Obama was inaugurated January 20, 2009.
- On January 29, 2010, DOE Secretary Chu announced a15-member panel of experts to "chart new paths to manage highly radioactive nuclear waste."
- On April 6, 2010, Steven Chu said, "We are taking steps to end [Yucca Mountain] because… we see no point in it. It's spending a lot of money. It's very important that we not linger around this decision. It's been made, and we want to go forward and move into the future."
- On April 7, the NRC said that it will not act on the DOE's motion to withdraw its application to construct the nuclear materials repository at Yucca Mountain until the court system rules on related lawsuits, and it will continue its work on the application review and expects to have a significant portion completed by November.

The next paragraph was adapted from [18]. Several generations of reactors are commonly distinguished.

• Generation I reactors were developed in 1950-60s; very few are still running today. They mostly used natural uranium fuel and used graphite as moderator.

• Generation II reactors are typified by the present US fleet and most in operation elsewhere. They typically use enriched uranium fuel and are mostly cooled and moderated by water.

• Generation III are the advanced reactors, the first few of which are in operation in Japan; others are under construction and ready to be ordered. They are developments of the 2nd generation with enhanced safety. More than a dozen Generation III advanced reactor designs are in various stages of development. Some are evolutionary from the PWR, BWR and CANDU designs, and some are more radical departures. The former include the Advanced Boiling Water Reactor, a few of which are now operating with others under construction. The best-known radical new design is the Pebble Bed Modular Reactor, using helium as coolant, at very high temperature, to drive a turbine directly.

•Generation IV designs are still on the drawing board and will not be operational after 2020. They will tend to have closed fuel cycles and burn the long-lived actinides now forming part of spent fuel, so that fission products are the only high-level waste. Many will be fast neutron reactors.

Table 5 [19] summarizes advanced reactors presently being marketed.

Table 5

Country and developer	Reactor	Size MWe	Design Progress	Main Features (improved safety in all)
US-Japan (GE-Hitachi, Toshiba)	ABWR	1300	Commercial operation in Japan since 1996-7. In US: NRC certified 1997, FOAKE.	• Evolutionary design. • More efficient, less waste. • Simplified construction (48 months) and operation.
USA (Westinghouse)	AP-600 AP-1000 (PWR)	600 1100	AP-600: NRC certified 1999, FOAKE. AP-1000 NRC certified '05.	• Simplified construction and operation. • 3 years to build. • 60-year plant life.
France-Germany (Areva NP)	EPR US-EPR (PWR)	1600	Future French standard. French design approval. Being built in Finland. US version developed.	• Evolutionary design. • High fuel efficiency. • Low cost electricity.
USA (GE)	ESBWR	1550	Developed from ABWR, under certification in USA	• Evolutionary design. • Short construction time.
Japan (utilities, Mitsubishi)	APWR US-APWR EU-APWR	1530 1700 1700	Basic design in progress, planned for Tsuruga US design certification application 2008.	• Hybrid safety features. • Simplified Construction and operation.
South Korea (KHNP, derived from Wstnghouse)	APR-1400 (PWR)	1450	Design certification '03, First units expected operational '12.	• Evolutionary design. • Increased reliability. • Simplified construction
Germany (Areva NP)	SWR-1000 (BWR)	1200	Under development, pre-certification in USA	• Innovative design. • High fuel efficiency.

Country and developer	Reactor	Size MWe	Design Progress	Main Features (improved safety in all)
Russia (Gidropress)	VVER-1200 (PWR)	1200	Replacement for Leningrad and Novovoronezh plants	• High fuel efficiency.
Russia (Gidropress)	V-392 (PWR)	950-1000	Two being built in India, Bid for China in 2005.	• Evolutionary design. • 60-year plant life.
Canada (AECL)	CANDU-6 CANDU-9	750 925+	Enhanced model Licensing approval 1997	• Evolutionary design. • Flexible fuel requirements. • C-9: Single stand-alone unit.
Canada (AECL)	ACR	700 1080	undergoing certification in Canada	• Evolutionary design. • Light water cooling. • Low-enriched fuel.
South Africa (Eskom, Westinghouse)	PBMR	170 (module)	prototype due to start building (Chinese 200 MWe counterpart under const.)	• Modular plant, low cost. • High fuel efficiency. • Direct cycle gas turbine.
USA-Russia et al (General Atomics - OKBM)	GT-MHR	285 (module)	Under development in Russia by multinational joint venture	• Modular plant, low cost. • High fuel efficiency. • Direct cycle gas turbine.

Because the Bush Administration was very pro-nuclear, and because of the high natural gas prices and concern over greenhouse gas, legislation was passed in 2005 called the 2005 Federal Energy Legislation. This legislation [20] provided the following:

Very generous for "first movers"!!!!

- *Loan guarantees*: of 80% of estimated project cost for first 6 plants to obtain licenses. Fed govt agrees to repay lenders if borrowers default.
- *Standby Support*: insurance to counter risk of delays in new plant construction due to litigation or NRC approval:
  - Up to $500 million to each of first two plants 1&2 (100% of delay costs)
  - Up to $250 million for plants 3-6
- *Production credits*: capped at 1.8¢/kWhr for first 8 years, applied to up to 6000 MW capacity operable before 1/1/21.
- *Funding support*: $1.18 billion for nuclear research, development, demonstration, and commercial application activities '07-'09.

In addition, there have been some other pro-nuclear developments:

1. The DOE NP 2010 Program was enacted that provides 50% sharing of cost of engineering on 2 new designs.
2. Streamlined NRC licensing process which combines construction and operating licensing processes.
3. Availability of new designs as indicated in Table 5. More specifically, there are currently four certified reactor designs that can be referenced in an NRC application for a combined license (COL)[3] to build and operate a nuclear power plant. They are:

[3] A COL is a NRC-issued license that authorizes a licensee to construct and (with certain specified conditions) operate a nuclear power plant at a specific site, in accordance with established laws and regulations. A COL is valid for 40 years (with the possibility of a 20-year renewal).

- Advanced Boiling Water Reactor design by GE Nuclear Energy (May 1997);
- System 80+ design by Westinghouse (formerly ABB-Combustion Engineering) (May 1997);
- AP600 design by Westinghouse (December 1999); and
- AP1000 design by Westinghouse (January 2006).

This activity has resulted in 24 projected new nuclear plants as of May 2007 as illustrated in Fig. 13e, updated to 23 as of January 2009 as illustrated in Fig. 13f, and to 19 as of July 2010 as illustrated in Fig. 13g. The projections are based on submitted combined license (COL) applications.

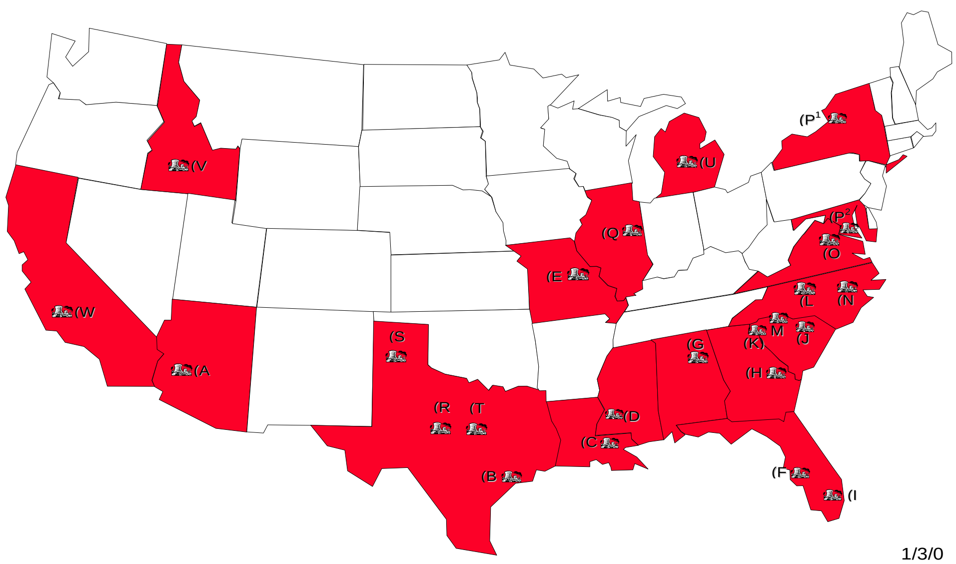


Fig. 13e: Projected nuclear plants as of 5/2007

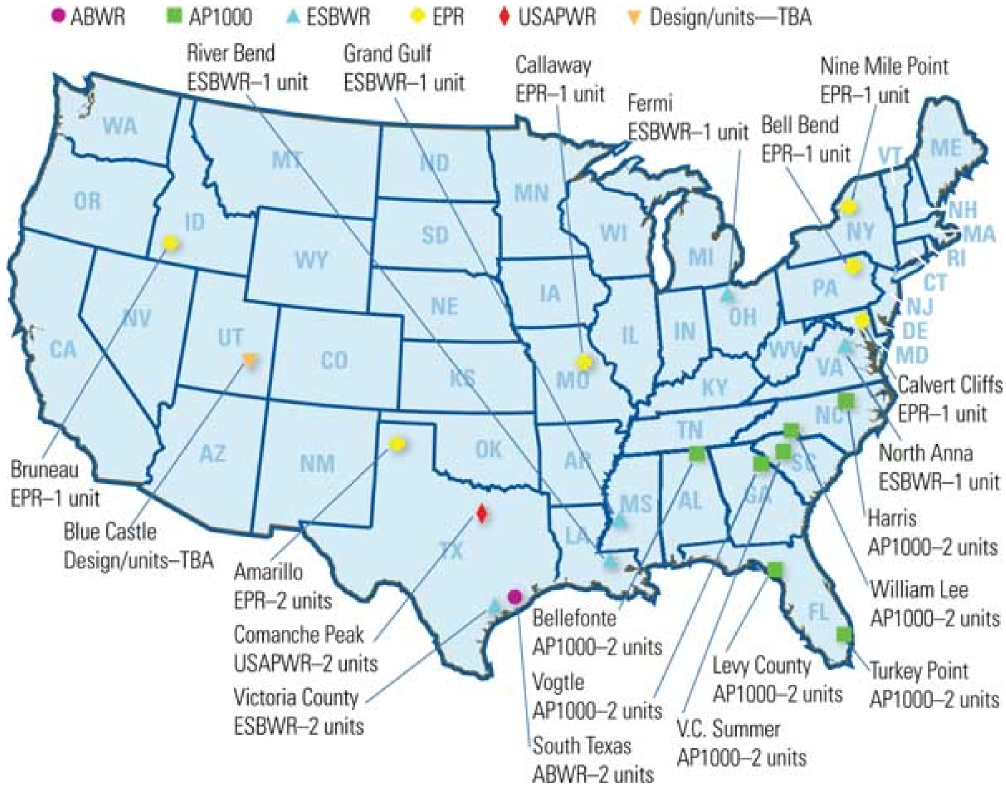


Fig. 13f: Projected nuclear plants as of 1/09

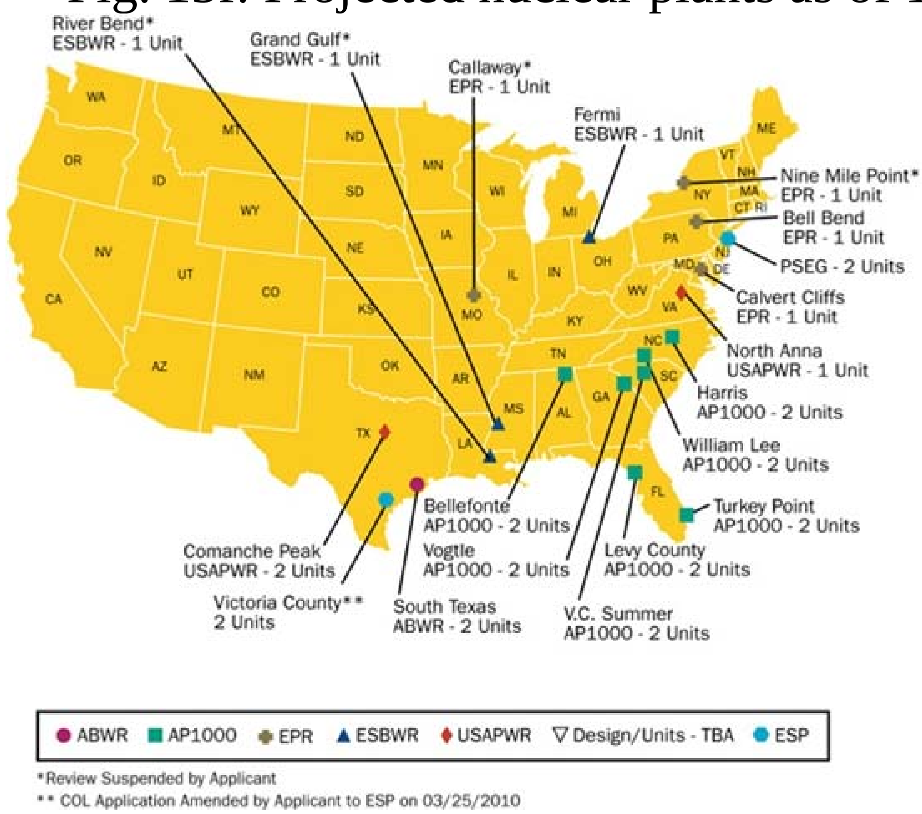


Fig. 13f: Projected nuclear plants as of 7/10

Some of these nuclear plants are described in more detail in Table 6.

Table 6: COL Applications Received as of 1/4/10

Proposed New Reactor(s)	Design	Applicant
Bell Bend Nuclear Power Plant	U.S. EPR	PPL Bell Bend, LLC
Bellefonte Nuclear Station, Units 3 and 4	AP1000	Tennessee Valley Authority (TVA)
Callaway Plant, Unit 2	U.S. EPR	AmerenUE
Calvert Cliffs, Unit 3	U.S. EPR	Calvert Cliffs 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC
Comanche Peak, Units 3 and 4	US-APWR	Luminant Generation Company, LLC (Luminant)
Fermi, Unit 3	ESBWR	Detroit Edison Company
Grand Gulf, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)
Levy County, Units 1 and 2	AP1000	Progress Energy Florida, Inc. (PEF)
Nine Mile Point, Unit 3	U.S. EPR	Nine Mile Point 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC (UniStar)
North Anna, Unit 3	ESBWR	Dominion Virginia Power (Dominion)
River Bend Station, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)
Shearon Harris, Units 2 and 3	AP1000	Progress Energy Carolinas, Inc. (PEC)
South Texas Project, Units 3 and 4	ABWR	South Texas Project Nuclear Operating Company (STPNOC)
Turkey Point, Units 6 and 7	AP1000	Florida Power and Light Company (FPL)
Victoria County Station, Units 1 and 2	ESBWR	Exelon Nuclear Texas Holdings, LLC (Exelon)
Virgil C. Summer, Units 2 and 3	AP1000	South Carolina Electric & Gas (SCE&G)
Vogtle, Units 3 and 4	AP1000	Southern Nuclear Operating Company (SNC)
William States Lee III, Units 1 and 2	AP1000	Duke Energy

Four of these have applied for Early-Site Permits[4], as indicated in Table 7.

[4] By issuing an early site permit (ESP), the U.S. Nuclear Regulatory Commission (NRC) approves one or more sites for a nuclear power facility, independent of an application for a construction permit or combined license. An ESP is valid for 10 to 20 years from the date of issuance, and can be renewed for an additional 10 to 20 years.

Table 7

Site	Applicant
Clinton ESP Site	Exelon Generation Company, LLC
Grand Gulf ESP Site	System Energy Resources Inc.
North Anna ESP Site	Dominion Nuclear North Anna, LLC
Vogtle ESP Site	Southern Nuclear Operating Company

But problems remain:

- Financing: They need funds 10-12 years before the first MW is sold from these units, and the federal assistance does not provide assistance to lenders with respect to this issue.
- Cost and excess cost: The capital cost is high ($5-7 billion). Given the first of a kind technologies, what if costs *greatly* exceed estimates?
- Human resources for nuclear engineering and technicians are almost nonexistent right now.
- The process of design certification and construction-operation licensing (COL) should be done sequentially, however, it is being done in parallel, causing significant concern. Reference [21] contains an excellent discussion of this issue which indicates:

  > “The AP1000 was pronounced "certified" by the NRC in January 2006, making it the first of the new third-generation reactors. Since that initial certification, a spokesman for these groups noted that Westinghouse has submitted 17 updates to the AP1000 certified design.”

  This has lead to the following kind of statements [21]

  > “It is clearly unlawful for the NRC to review license applications prior to genuine certification of the AP1000 design," explained Lou Zeller of the Blue Ridge Environmental Defense League, which is leading the federal intervention against Duke Energy’s proposed Lee 1 and 2 reactors in South Carolina and TVA’s Bellefonte project in Alabama. "The industry jumped the gun before the blueprints were finished, but they cannot redirect their problem onto interveners and NRC staffers trying to review these ever-changing, complex documents."

9.0 Hydroelectric plants

The US has already developed most hydroelectric facilities. It is possible to uprate some existing facilities, and this may well be done. Nonetheless, most studies are consistent in assuming that hydroelectric should not be considered as a significant player in supplying future additional US electric energy needs. For example, a recent DOE study [22] indicates that additional hydroelectric capacity should not exceed 4.3 GW. An exception to this would be pumped storage.

10.0 Wind plants

There is extreme interest in growing wind energy throughout the nation, particularly where wind speeds make it attractive to do so.

However, wind is highly variable, imposing additional uncertainty on load variation that must be covered by increased reserves. But there appear to be solutions to this problem, including deployment of various kinds of storage coupled with fast response machines. If this is the case, the amount of wind that can be built in the US far exceeds the transmission capacity for moving it. This fact has motivated the Midwest ISO to propose building a new transmission overlay to move Midwest wind energy to the east coast, as illustrated in Fig. 15b.

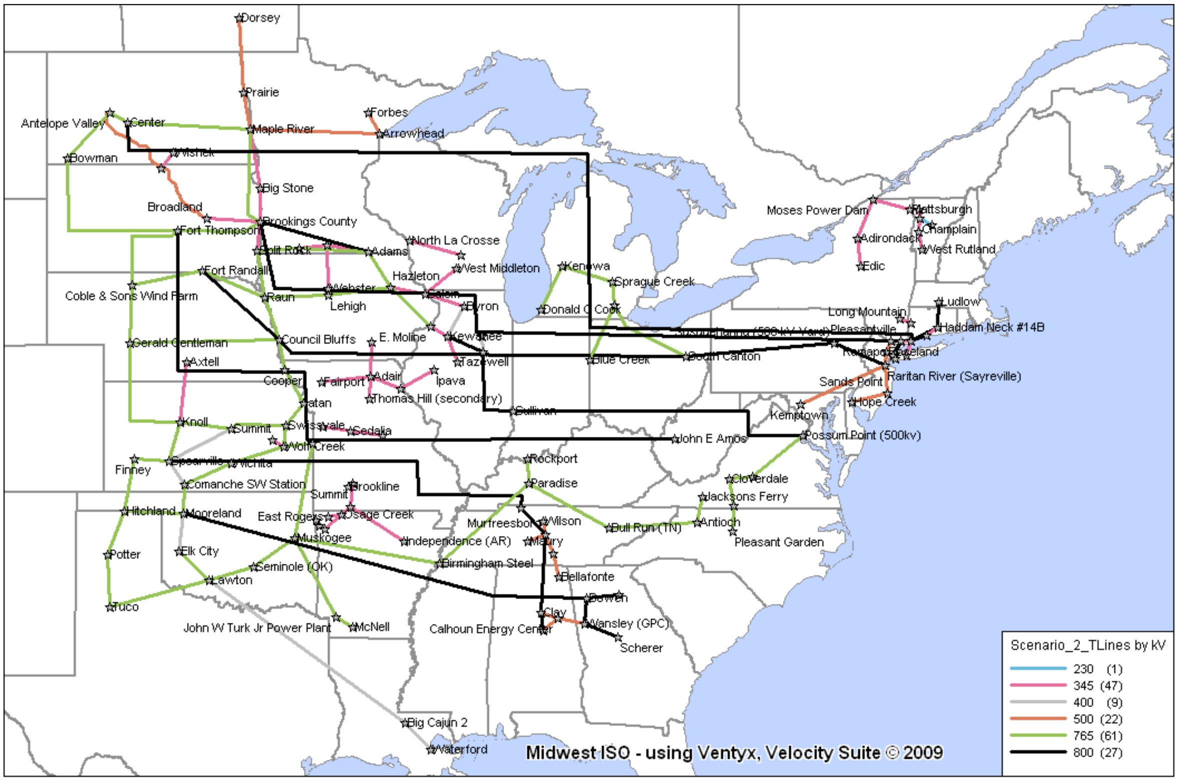


Fig. 15b: Proposed transmission overlay

Likewise, the American Electric Power (AEP) Company was recently cited in the recent DOE wind study [23] as authors of a preliminary proposal for a national 765 kV overlay, as illustrated in Fig. 15c.

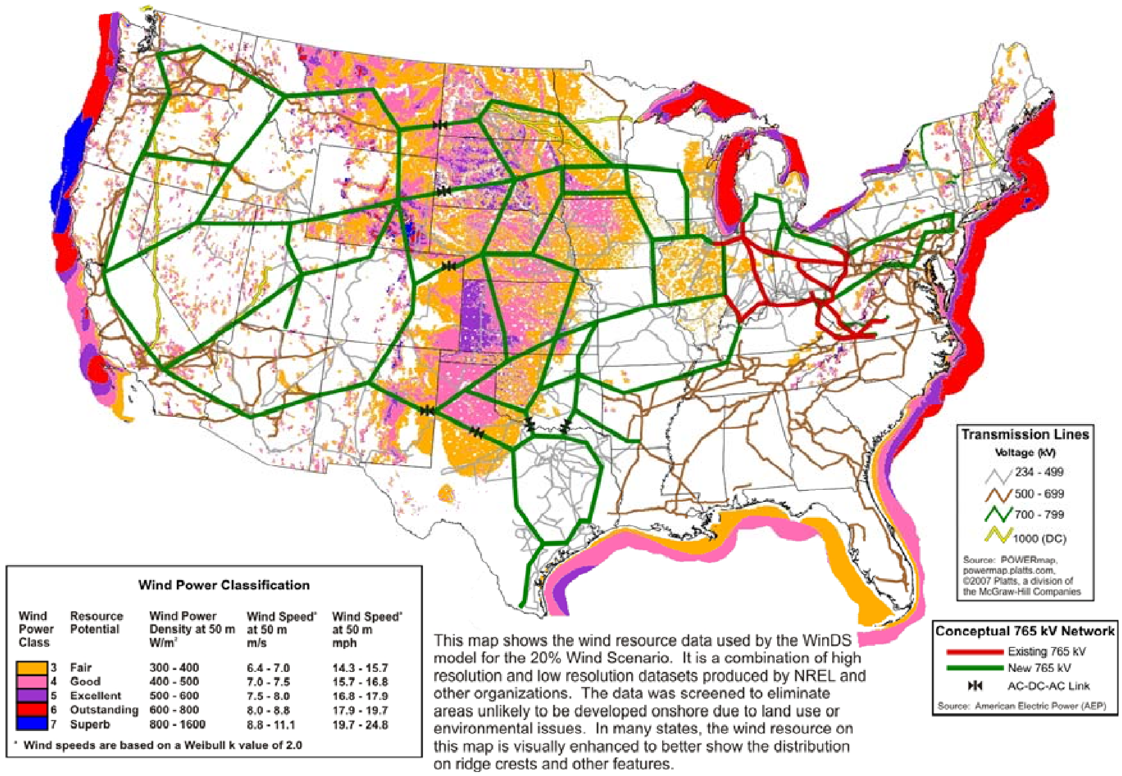


Fig. 15c: AEP’s conceptual for moving wind energy

> This kind of transmission design is no longer incremental, and it therefore requires significantly new design methods. We will study some of these in this course.

Wind is currently only supplying about 3% of national electric energy needs. However, for those regions of the country where there is good wind potential (in order of potential: *North Dakota*, Texas, *Kansas*, *South Dakota*, Montana, *Nebraska*, Wyoming, *Oklahoma*, *Minnesota*, *Iowa*, Colorado, New Mexico, Idaho, Michigan, New York, *Illinois*, California, *Wisconsin*, Maine, and *Missouri – Midwest states in italics*), wind generation has been growing at an amazing rate. In 2006, there was 1 GW of wind capacity; that doubled by 2008! There are several reasons for this, but one of them is that wind is a very buildable electric energy resource, and in some states, it is the only buildable electric energy resource, due to the fact that it requires very little in the way of land, permitting, and time.

- It can be built quickly, within 1-3 years of initiation
- It is economically competitive with the following data representing typical wind power costs [24]:
  - Private ownership, project financing: 4.95 cents/kWh including PTC, 6.56 cents/kWh without.
  - IOU ownership, corporate financing: 3.53 cents/kWh including PTC, 5.9 cents/kWh without.
  - Public utility ownership, internal financing: 2.88 cents/kWh including REPI, 4.35 cents/kWh without.
  - Public utility ownership, project financing: 3.43 cents/kWh including REPI, 4.89 cents/kWh without.

In the above, PTC is the production tax credit. Because public utilities do not pay tax, the Renewable Energy Production Incentive (REPI) was developed as a payment to public utilities to compensate for the fact that since they are not subject to federal taxes, they cannot qualify for the PTC. However, since REPI is not a tax deduction, money must be appropriated for it each year by Congress, and thus it is viewed by the financial community as subject to considerable risk.

Of course, wind does have its problems, including:

- Its variability and associated cost of increased reserves
- Lack of adequate transmission to bring it from areas of high wind potential (e.g., North Dakota) to areas of high load.

There is evidence of solutions to these two problems.

Variability issues may become less significant as wind penetration levels grow, and to the extent that these issues remain, solutions may be on the horizon in the form of improved short-term forecasting methods for wind, increased use of fast-ramping generation, and innovative ways to couple wind with storage mechanisms.

In regards to transmission, there is an organization dedicated to addressing this issue, called "Wind on the Wires," [25], with a mission of

> "providing wind energy with fair access to the electric transmission system that delivers power to market. This includes both better use of

> existing transmission and getting more transmission constructed."

They list "technical issues" as one of their three primary focus areas, describing it this way

> "We work with utilities, the Midwest Independent System Operator (a regional transmission "grid" operator: www.midwestiso.org), and other stakeholders on comprehensive, integrated, forward-looking transmission planning."

Another indication of activity regarding addressing interstate transmission needs was a recent announcement [26] that governors from Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin are banding together to develop transmission plans to submit to the Midwest ISO which would improve the interstate transmission system, with comments:

• "The time is right for planning and coordination between these states in the Midwest ISO," said Minnesota Gov. Tim Pawlenty. "As states in the region increase their use of wind energy, planning on how best to locate wind farms and other renewable sources and build the necessary transmission infrastructure to support them is crucial."

•"This effort complements and meshes very well with ongoing initiatives at MISO and the Midwest

Governors Association," added South Dakota Gov. Mike Rounds, MGA[5] chairman.

A final comment about transmission: The need is driven by the fact that most of the richest wind regions (Midwest) are remote from load centers (on the coast). This statement is, however, based on the assumption that we are considering only land-based wind energy systems. Offshore wind generation is realizable as a future resource, and it would largely solve the problem associated with interstate transmission. We describe offshore wind technologies

Biomass

The term biomass includes use of organic matter e.g., wood residues (saw dust, wood chips, wood waste such as pallets and crates), agricultural waste (corn stovers and rice hulls), energy crops (hybrid poplar, switchgrass, and willow), and municipal waste (garbage) to produce

- Biofuels: ethanol, methanol, methane, hydrogen, biodiesel or
- Biopower: converting organic matter to electricity.

Today, most attention is on biofuels (e.g., the US DOE's Energy Efficiency and Renewable Energy webpages are almost entirely devoted to biofuels).

[5] Midwest Governor's Association

Mainly as a result of the 1978 PURPA legislation, biopower comprises the largest single non-hydro electric renewable resource in the US, with 11 GW of installed capacity [27] (remember, wind is presently at 2 GW). Of these 11 GW, about 7.5 GW utilize forest product or agricultural residues, 3.0 GW is municipal solid waste (MSW), and 0.75 GW is landfill gas.

There are three main ways to produce biopower [28]:

1. Direct-fired systems: This uses conventional steam-cycle technology where the biomass fuel is burned in a boiler to produce high-pressure steam which in turn drives a steam turbine. Most of these systems are relatively small (0-50MW) and unable to economically justify efficiency-improving technologies. Thus, overall plant efficiencies tend to be in the 20-30% range.
2. Cofiring: Here, biomass is substituted for a portion of coal in an existing power plant furnace. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, cofiring is far less expensive than building a new BioPower plant. Compared to the coal it replaces, biomass reduces SO_2 and NO_x. Efficiencies are about the same as a conventional pulverized coal plant (33-37% range).

3. <u>"Slow" pyrolysis</u>: This is a century-old technology whereby biomass is heated so that the solid biomass breaks down to form a flammable gas. The heating process is called pyrolysis, which is the thermal decomposition of biomass fuels in the absence of oxygen [29]. The biogas, also called producer gas, is a mixture of combustible and non-combustible gases, as illustrated in Fig. 16 [30]. The quantity of each gas constituent depends upon the type of fuel and operating condition. These gases can be filtered and then used in internal-combustion engines or combined-cycle plants.

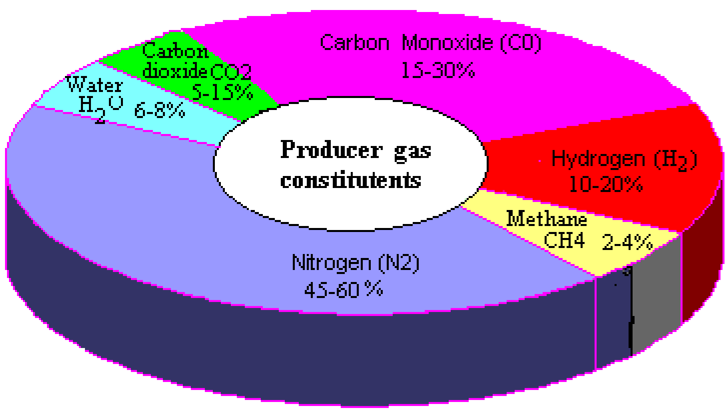


Fig. 16

It is of interest that the City of Ames, Iowa has a co-firing facility called the Arnold O. Chantland Resource Recovery Plant (RRP). Built in 1975, the RRP separates burnable and non-burnable garbage; the burnable portion becomes refuse derived fuel (RDF), used as a supplemental fuel in the coal boilers of the city's power plant to generate electricity [31].

Another interesting local co-fired example is the 726 MW Ottumwa Power Plant in Ottumwa, Iowa, a pulverized coal facility. By using switchgrass for about two percent of the heat input, data shows there was a 4.5 percent reduction in SO_2 emission and a 4 percent reduction in particulate emissions, and that the power plant's efficiency was retained. The intention is to displace up to 5% of the unit's coal with switchgrass [32].

11.0 Energy conversion technologies of the future

<u>IPCC</u>

There are essentially four ways to convert biomass to an energy product:

1. Air-gasification of biomass is the most flexible and best developed process for conversion of biomass to fuel, yielding a low energy gas that can be burned in existing gas/oil boilers or in engines.
2. Oxygen-gasification yields a gas with higher energy content that can be used in pipelines or to fire turbines. In addition, this gas can be used for producing methanol, ammonia, or gasoline by indirect liquefaction. This is what is used in IGCC.
3. "Slow" pyrolysis of biomass is a particularly attractive process if all three products bio-oil, char,

and syngas are equally of interest. This process produces these on a weight basis of approximately 30%, 35%, and 35%, respectively, and the gas is called “producer gas” as indicated at the end of Section 2.0 above.

4. “Fast” pyrolysis of biomass produces a gas rich in ethylene that can be used to make alcohols. “Fast” pyrolysis, where the process is controlled to enable fast heating and cooling rates, produces bio-oil, char, and syngas at weight ratios of 75%, 12%, and 13%, respectively. The liquid “bio-oil” is illustrated in Fig. 17 [33].

The main difference between gasification and pyrolysis is that gasification is performed with oxygen (or air) and pyrolysis is not.

Fig. 17

The resulting bio-oil may be used in diesel engines or converted to a transportation fuel (synfuel) using Fischer-Tropsch [34] (to run trucks, cars, and some aircraft engines), or it can be used directly in an electric power generation process [35], as illustrated in Fig. 18 [36].

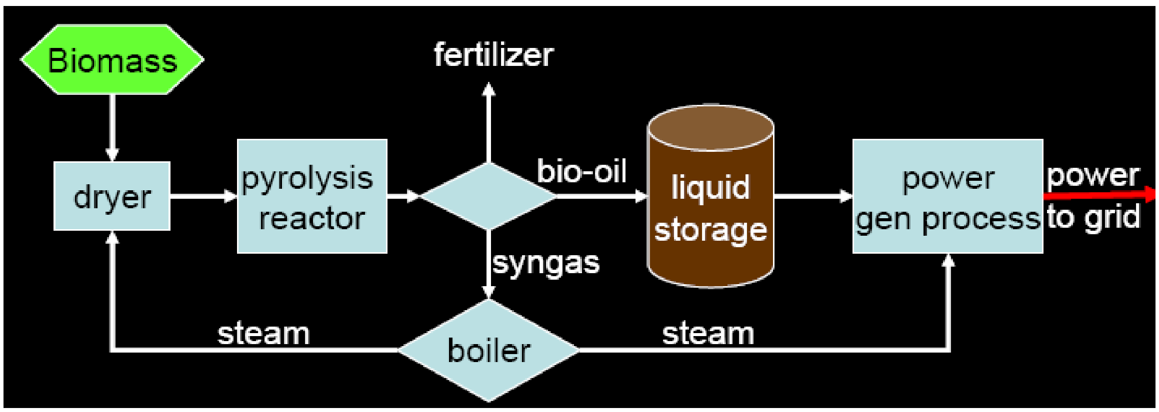


Fig. 18

The power generation process may be implemented by using the bio-fuel to power a combustion turbine [37]. The combustion turbine may be paired with a heat-recovery steam generator to produce steam in driving another turbine, resulting in a combined cycle configuration called an integrated pyrolysis combined cycle (IPCC) system, illustrated in Fig. 19 [33] (note tph is ton per hour).

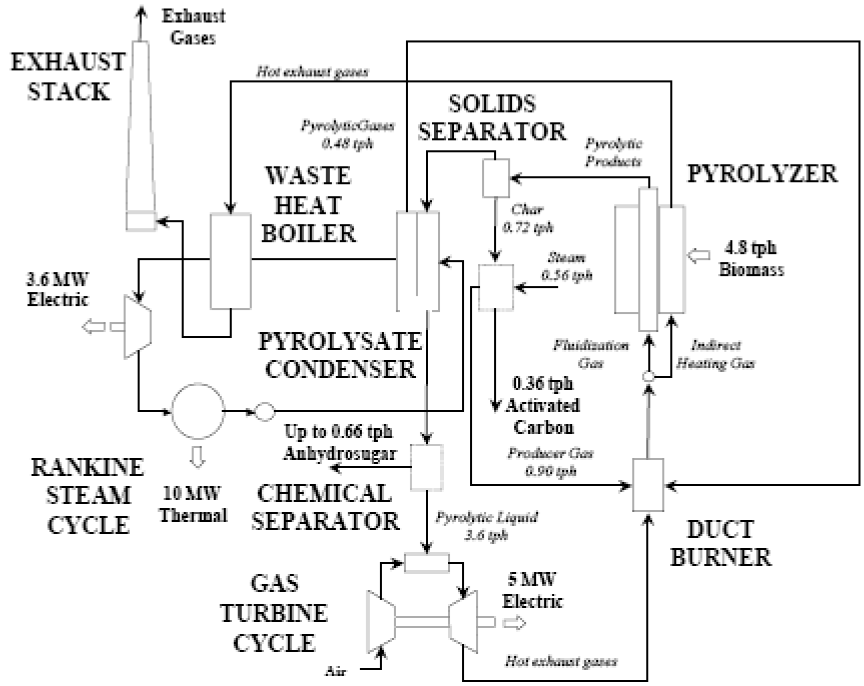


Fig. 19

The solid product (bio-char) can be combusted or sequestered as a soil amendment or carbon sequestration agent. Bio-char benefits include increased soil water availability and organic matter and enhanced nutrient cycling [38]. A recommended selling price for bio-oil is $0.62 per gallon with capital costs of $28 million for a 550 ton per day (tpd) facility.

Geothermal

Enhanced Geothermal Systems (EGS) involves drilling two wells 10,000-30,000ft into the Earth's crust. The injection well pumps water into the hot rock producing steam; the steam is then returned to the surface via the production well and expanded through a turbine driving an electric generator, as illustrated in Fig. 20 [39].

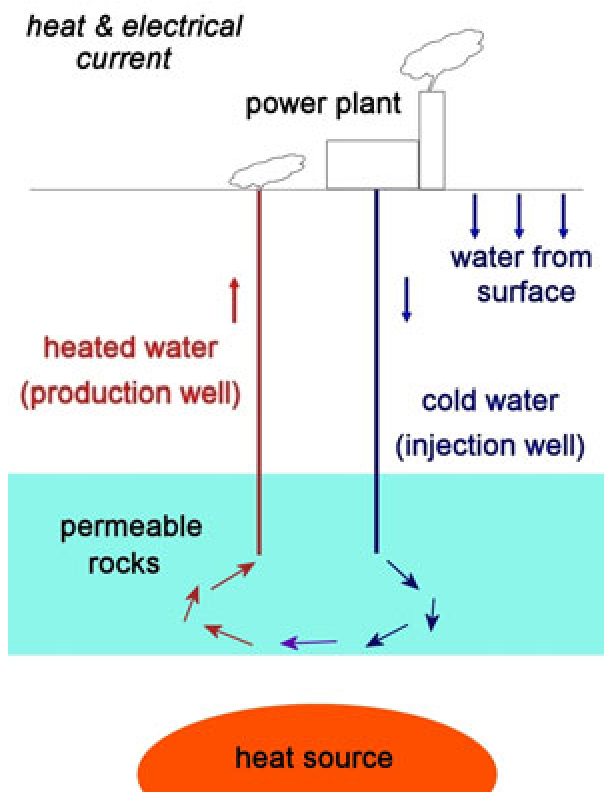


Fig. 20

These plants have no emissions. More than 100 GW of power is estimated available in the U.S. Currently, EGS is expensive and will need investment to be competitive [40]. Scalability depends on the source quality, as steam handling equipment is well-developed; well depth is currently limited to 30,000 ft.

Figure 21 [40] shows underground temperature gradients across the US for three different depths: 3.5 km (2.2 miles, 11482 ft), 6.5 km (4.04 miles, 21325 ft), and 10 km (6.2 miles, 32,808 ft). It is clear from these figures that, for a given depth, the Western US has significantly higher temperatures than the Midwestern or Eastern US, and that within the depths explored, some temperatures are only obtainable in the west.

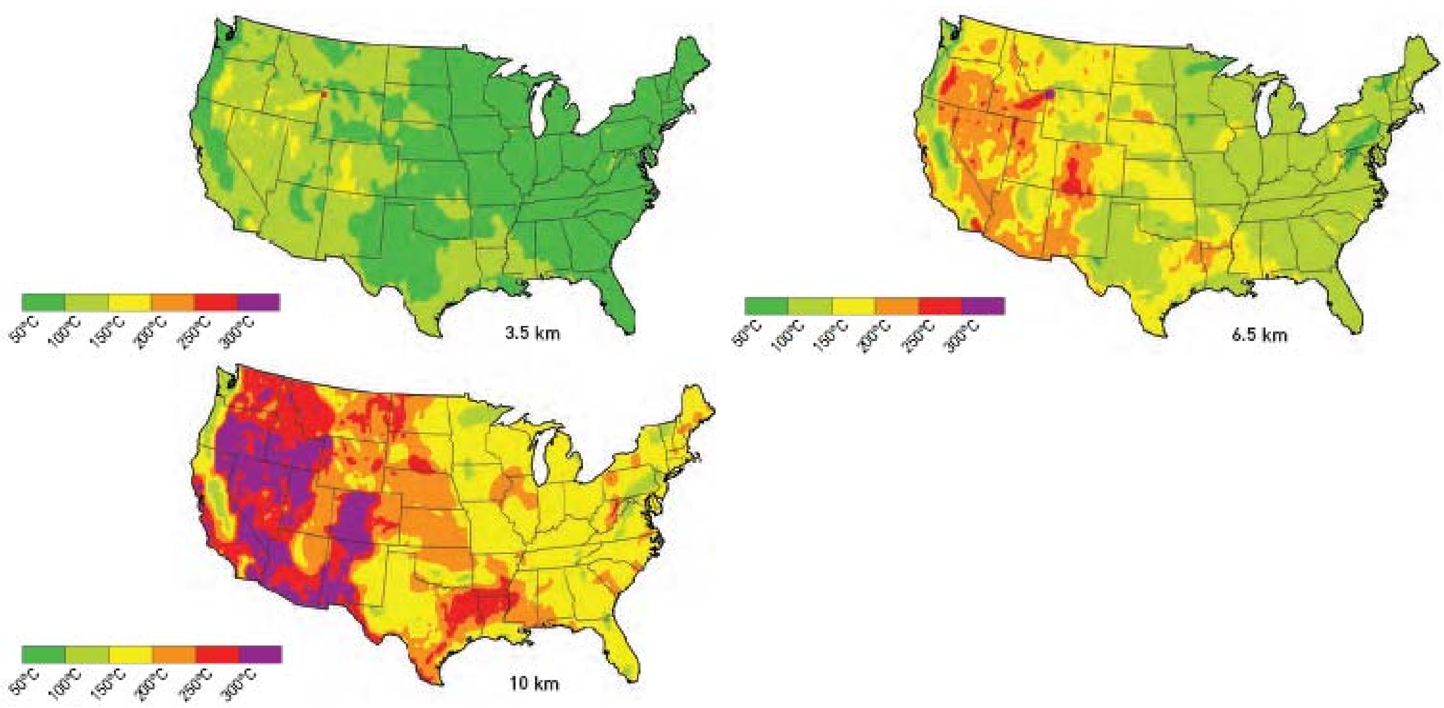
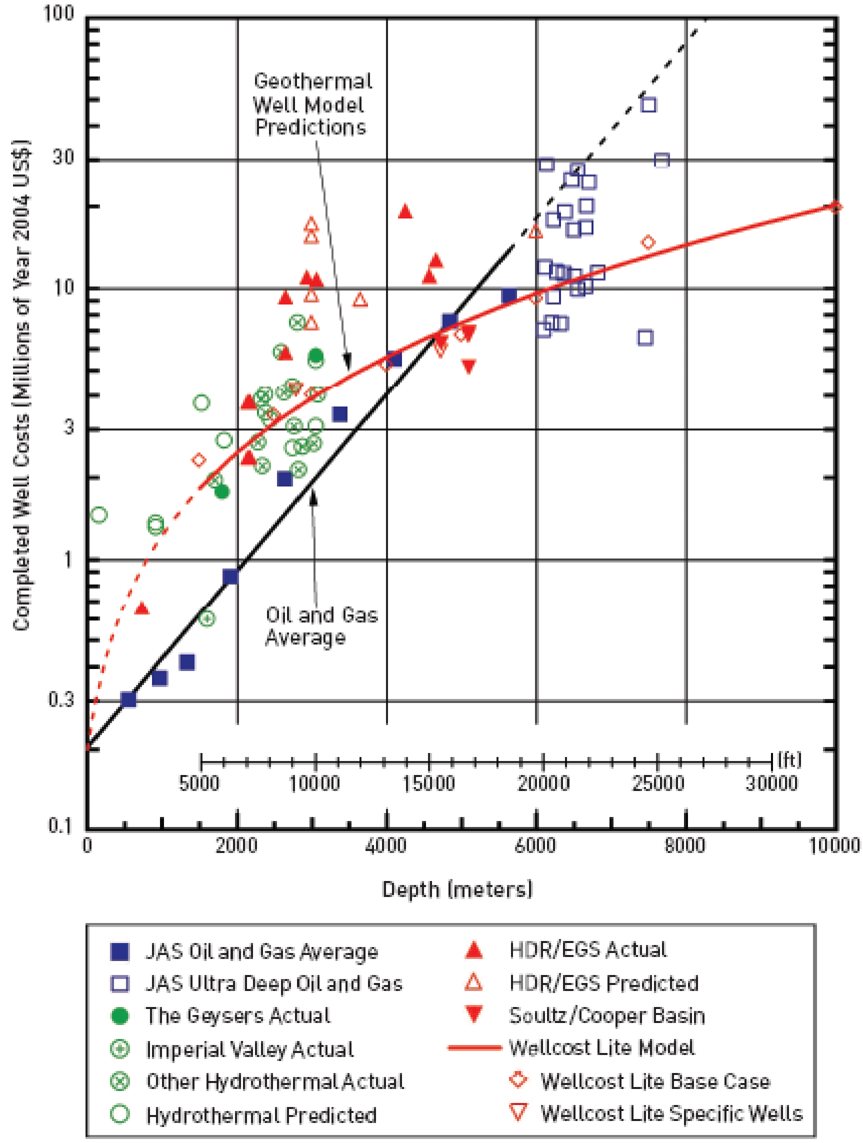


Fig. 21

The cost of this energy is mainly associated with the investment cost. Fig. 22 [40] illustrates well-cost as a function of depth, in comparison to oil and gas well costs.



1. JAS = Joint Association Survey on Drilling Costs.
2. Well costs updated to US$ (yr. 2004) using index made from 3-year moving average for each depth interval listed in JAS (1976-2004) for onshore, completed US oil and gas wells. A 17% inflation rate was assumed for years pre-1976.
3. Ultra deep well data points for depths greater than 6 km are either individual wells or averages from a small number of wells listed in JAS (1994-2000).
4. "Other Hydrothermal Actual" data include some non-US wells (Source: Mansure 2004).

Fig. 22

Total overnight costs of EGS, including present value of fuel costs, are $1746/kW, in contrast to nuclear, PC, IGGC, which are $2144, $1119, and $1338 [40].

Off-shore wind

All of the material in this section was adapted from [41], unless otherwise indicated.

The US currently has no operational off-short wind energy facilities, although there are at least three facilities in the planning stages (Massachusetts, Long Island NY, and Galveston, Texas). In contrast, European offshore wind energy production began in 1991 and has grown to include 25 projects in 5 countries comprising over 1100 MW, as indicated in Fig. 23 [42].

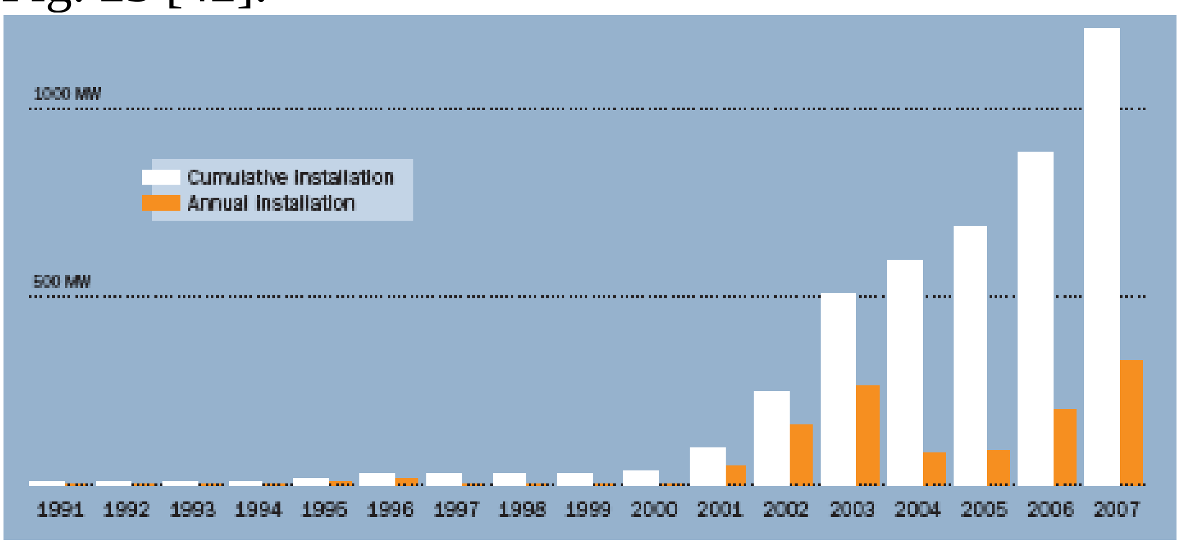


Fig. 23

Figure 24 shows some European installations.

Fig. 24

It is estimated that over 900 GW (just a little less than current US generating capacity) of potential wind capacity exists off the US coasts in the 5-50 mile zone, excluding the area needed for shipping lanes and avian, marine mammal, and fish concerns, and not accounting for the Great Lakes. Of this, about 10% is in waters that are less than 30 meters deep, and most of this is off the New England and mid-Atlantic states on the east coast. The fact that lower depth waters are much more attractive is because existing offshore technologies available in Europe today are likely to be useful at these depths. The other 90% is in waters deeper than 30 meters and therefore would likely require development of new offshore technologies.

Some interesting issues about off-shore wind include:

• Ocean wind direction is less variable due to flatter terrain and therefore turbines can be sited closer.

- Relative to onshore turbines, off-shore turbines must account for
  - the strong wind-wave interactions via stronger tower designs firmly set in the seabed via, for example, by steel tubes
  - the corrosive effect of the salty sea;
  - the need to provide undersea collection via sea-floor cables, sea-based transformation and transmission to the shore (usually 33 kV).
- US off-shore sites are generally harsher than existing European sites: not only is the ocean deeper, but the weather tends to be more severe.
- There is potential for deep-water offshore wind, at levels of 100 meters or more, as indicated in Fig. 25.

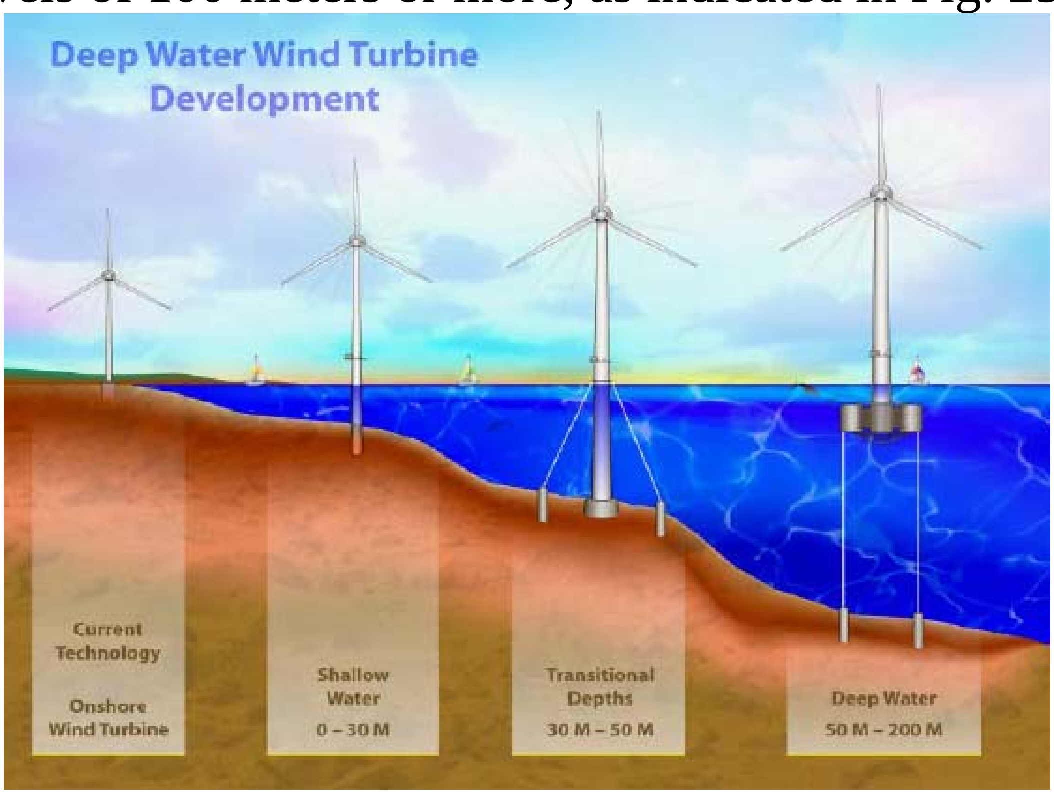


Fig. 25

Offshore wind costs per kW are quite variable, depending on size of turbines, how many turbines, distance from shore, water depth, mean wind speed, turbine reliability and maintainability, and site accessibility. Some typical costs for North Sea (Europe) off-shore wind are reported as [43]

- Turbine costs (inc. tower): $800-1000/kW
- Cable costs: $500k-$1,000,000/mile (10 miles out for a 50 MW facility could add $400/kW)
- Foundation costs:
  - Costs depend on soil and depth
  - North Sea: $300-350/kW
- Total overnight costs: $1200-$1800/kW

That actually sounds OK when compared to other technologies: recall that some typical numbers for geothermal is $1746/kW, nuclear is $2144, PC is $1119, and IGGC is $1338 [40]. However, that does not account for the fact that North Sea offshore is in 5-12 meter water, and most US water is more than 15 meters. Foundation costs increase significantly as depth increases, possibly to $600/kW or more for 30 meter water.

Solar

There are 3 basic ways to utilize solar energy: photovoltaic, concentrated, and solar heating. In the last one, solar heating, collectors absorb the solar energy for direct use in heating water or space in buildings. We will focus more on the first two, since they represent the ways to generate electricity.

Concentrating solar

Concentrating solar uses mirrors to focus solar energy on a liquid which is then used to produce steam which drives a turbine. The only place in the US where concentrating solar comes reasonably close to being economic is in the Southwest. Figure 26 shows the high-yield regions of the Southwest.

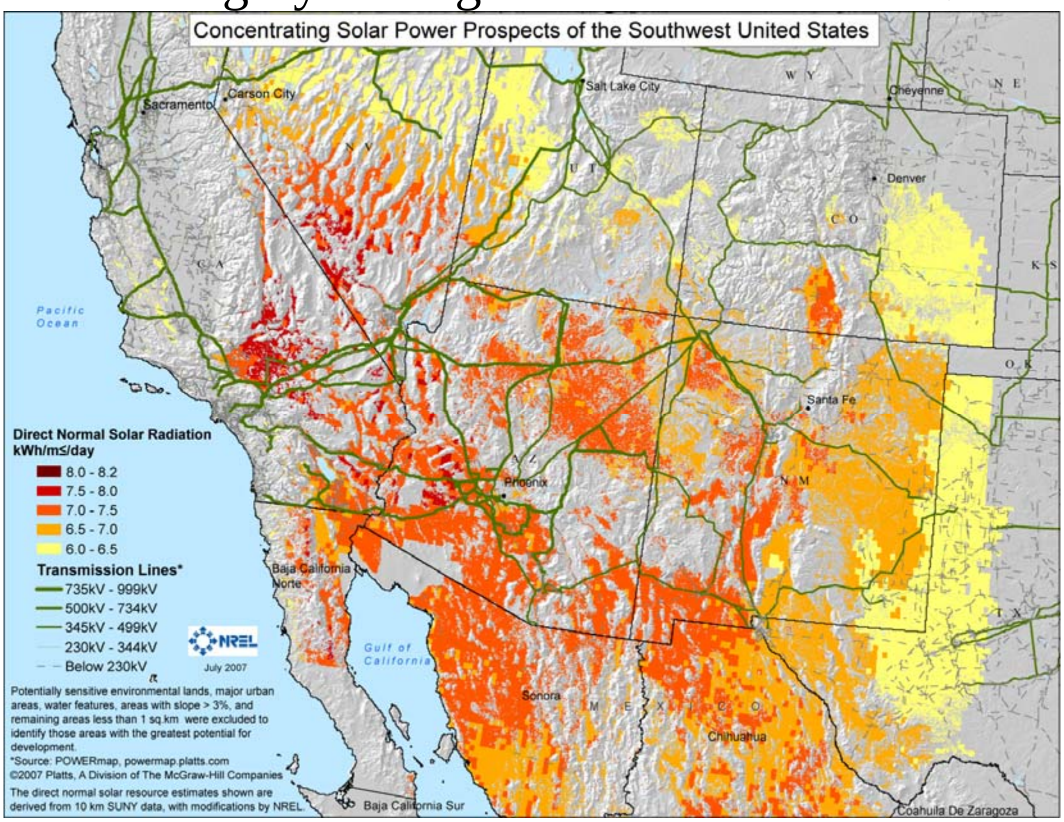


Fig. 26

There are three types of concentrating solar technologies: trough systems, dish/engine systems, and power towers.

Trough systems: Here, oil in receiver tubes collect the concentrated solar energy as heat. The oil is then pumped to a power generation facility to develop steam for generating electricity. The Kramer Junction, California facility is shown in Fig. 27 [44, 45]. The overall efficiency from collector to grid, i.e. (Electrical Output Power)/(Total Impinging Solar Power) is about 15%.

Fig. 27

Most trough systems today utilize a Rankine cycle steam process to generate electricity, but an interesting alternative is the integrated solar combined cycle system (ISCCS), shown in Fig. 28. Peak thermal-to-electric efficiency can exceed 70% for an ISCCS plant compared to 50-55% for a conventional gas-fired combined cycle plant. Current commercial plants utilizing parabolic troughs use fossil fuels during night hours, but the amount of fossil fuel used is limited to a maximum 27% of electricity production, allowing the plant to qualify as a renewable energy source.

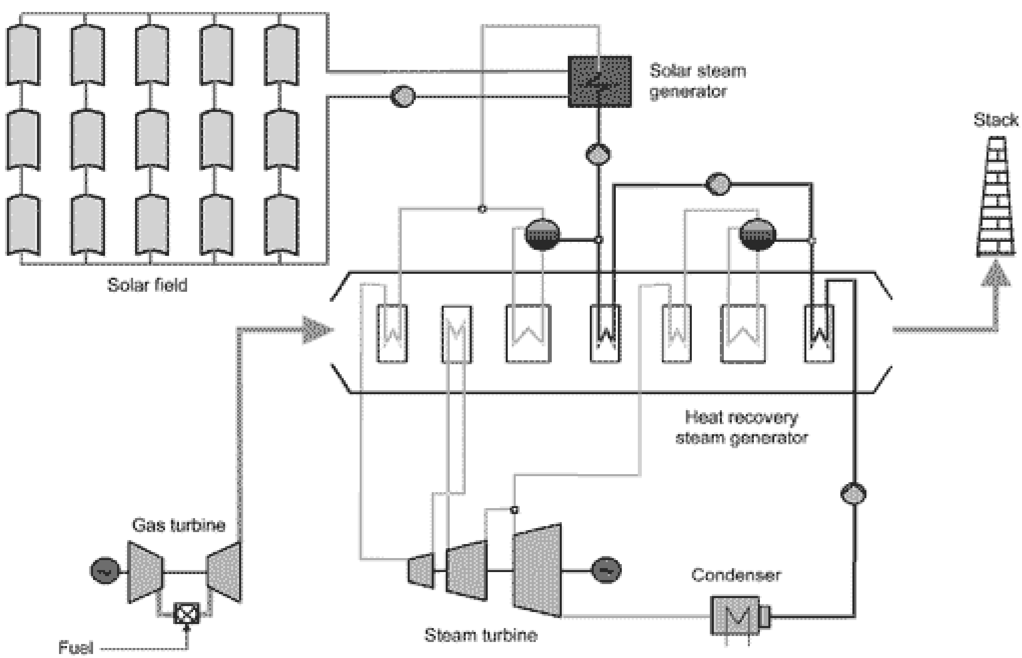


Fig. 28

The largest operational solar power system at present is located at Kramer Junction in California, USA, with five fields of 33 MW generation capacity each. There is also a 64 MW plant in Nevada.

Dish/engine systems: From [46], dish/engine concentrating solar power uses a mirror in the shape of a dish to collect and concentrates the sun's heat onto a small area where a receiver is located. The receiver transfers the sun's energy to a heat engine, usually a Stirling cycle engine, that converts the energy into power. A facility at Sandia National Labs, Fig. 29, in operation since 2005, cost about $6000/kW, but researchers believe that cost will decrease to $2000/kW before

Fig. 29

Of all the solar technologies that have been demonstrated on a practical scale the solar dish has the highest efficiency at 30%. The electricity needs of the entire U. S. could theoretically be met by such a system, in the desert, in an area 100 miles on a side.

Photovoltaic solar

Photovoltaic solar, Fig. 30, is attractive but costly. Reference [47] reports that the installed costs are above \$8000/kW-peak, and that, depending on location, energy costs are ~20-30 cents/kWh.

Fig. 30

Ocean

There are essentially three forms of ocean energy, and a related form of river-energy [48]: thermal energy, wave energy, tidal-in-stream energy, and river-in-stream energy. We will discuss each of these [49].

Thermal energy: See

http://en.wikipedia.org/wiki/Ocean_thermal_energy_conversion.

Wave energy: This energy results from ocean waves, which are generated by the influence of the wind on the ocean surface first causing ripples. As the wind continues to blow, the ripples become chop, fully developed seas, and finally swells. Wave energy may be harnessed in essentially four ways: point absorbers, oscillating water columns, overtopping terminators, and attenuators. Of these, the attenuators are the most technologically mature, illustrated in Fig. 31.

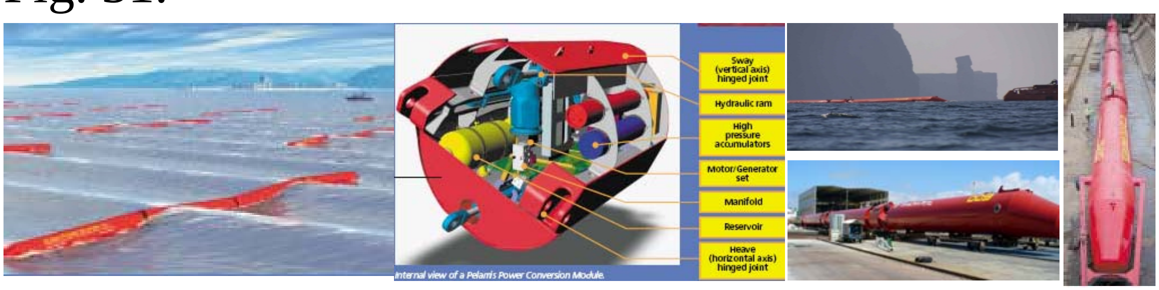


Fig. 31

The structure is composed of multiple sections that move relative to each other. That motion is used to pressurize a hydraulic piston arrangement and then turn a hydraulic turbine/generator to produce electricity. A test facility has been deployed in Orkney, off the North Coast of Scotland.

Tidal in stream energy: This energy results from the moving mass of water with speed and direction as caused by the gravitational forces of the sun and the moon, and centrifugal and inertial forces on the earth's waters. There have been a number of proposed designs of tidal-in-stream energy conversion systems (TISECS), as indicated in Fig. 32, but there has been only one seabed-fixed installation, Fig. 33, in Lynmouth, UK.

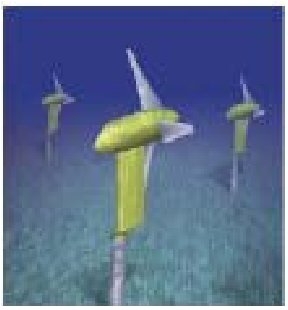
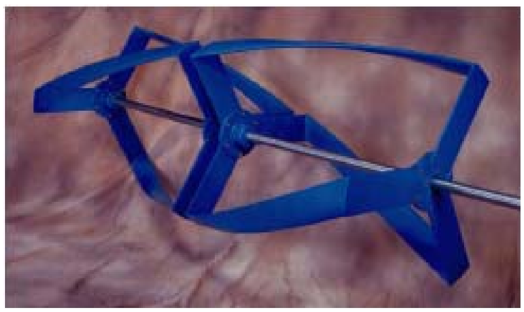




Fig. 32

Fig. 33

River in stream energy: This results from the hydrokinetic energy of the moving river water. The velocity of the river current is a function of the slope of the reach and the effect of gravity and the roughness of the riverbed and the effect of frictional forces slowing the current. River-in-stream energy conversion systems (RISECS) under consideration are similar to TISECS. It differs from conventional run-of-river hydro in that conversion equipment is entirely submerged.

Distributed generation

Distributed generation is the use of small-scale power generation technologies located close to the load being served. It includes reciprocating engines, microturbines, fuel cells, combustion gas turbines, and CTs, wind, and solar when those installations are dedicated to serve nearby load.

Reciprocating engines: These engines use reciprocating pistons to convert pressure into a rotating motion. The standard gasoline engine in automobiles is a reciprocating engine, but DG applications are generally fueled by either diesel or natural gas.

Microturbines: Microturbines are very high-speed, small combustion turbines, approximately the size of a refrigerator, with outputs of 25-500 kW, as illustrated in Fig. 34.

Fig. 34

Microturbines consist of a compressor, combustor, turbine, power electronics converter circuit, and generator, as illustrated in Fig. 35 [50]. The converter circuit is needed because of the high frequency power that is generated by the microturbine.

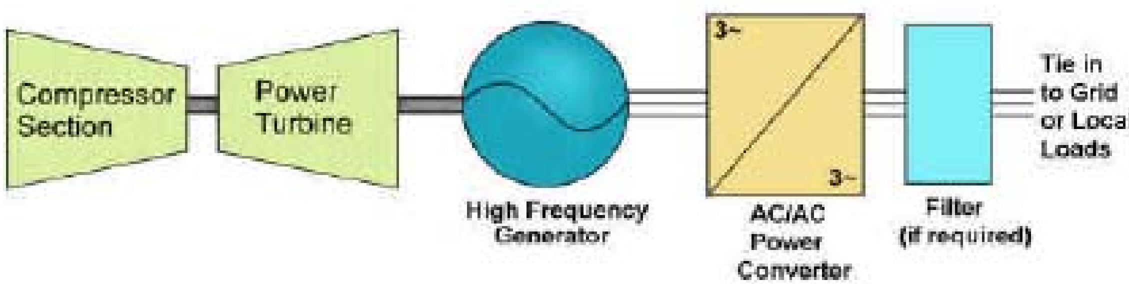


Fig. 35

Most designs use a high-speed permanent magnet generator producing variable voltage, variable frequency AC power. In addition, almost all new installations are *recuperated* to obtain higher electric efficiencies. The recuperator recovers heat from exhaust gas in order to boost the temperature of the air stream supplied to the combustor. Further exhaust heat recovery can be used in a cogeneration configuration. Figure 36 illustrates a recuperated microturbine system.

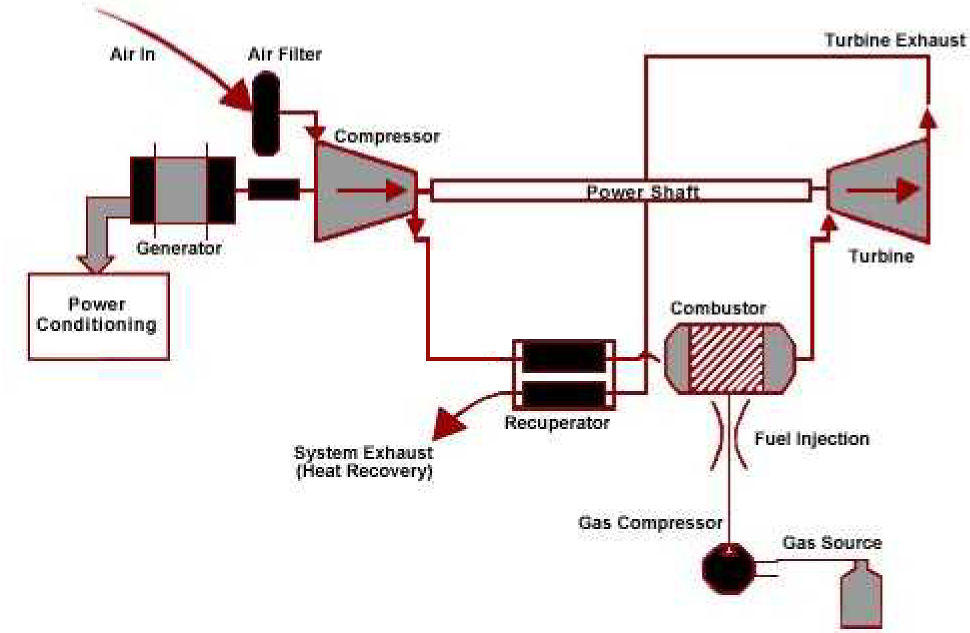


Fig. 36

Fuel cells: Fuel cells are illustrated in Fig. 37.

Fig. 37

A fuel cell consists of two electrodes separated by an electrolyte. Hydrogen fuel is fed into the anode of the fuel cell. Oxygen (or air) enters the fuel cell through the cathode. The hydrogen atom splits into a proton (H+) and an electron. The proton passes through the electrolyte to the cathode and the electrons travel in an external circuit through the load. At the cathode, protons combine with hydrogen and oxygen, producing water and heat. Figure 38 illustrates this process.

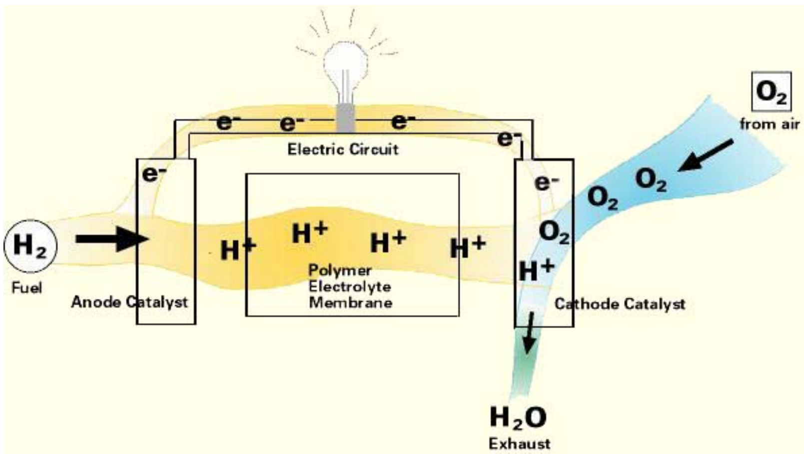


Fig. 38

There are five types of fuel cells, depending on the choice of electrolyte and include [51]:

- Alkali fuel cells use a solution of potassium hydroxide in water as their electrolyte. Efficiency is about 70%, and operating temperature is 150 to 200 degrees C, (about 300 to 400 degrees F). Cell output ranges from 300 watts to 5 kilowatts (kW).
- Molten Carbonate fuel cells (MCFC) use high-temperature compounds of sodium or magnesium carbonates (CO3) as the electrolyte. Efficiency ranges from 60-80%, and operating temperature is

about 650 degrees C (1,200 degrees F). Units with output up to 2 MW have been constructed, and designs exist for units up to 100 MW.

- Phosphoric Acid fuel cells (PAFC) use phosphoric acid as the electrolyte. Efficiency ranges from 40-80%, and operating temperature is between 150-200° C (300-400° F). Existing phosphoric acid cells have outputs up to 200 kW; 11 MW units have been tested.
- Proton Exchange Membrane (PEM) fuel cells work with a polymer electrolyte in the form of a thin, permeable sheet. Efficiency is about 40-50%, and operating temperature is about 80° C (175° F). Cell outputs generally range from 50-250 kW. These cells operate at a low enough temperature to make them suitable for homes & cars. All automotive applications of fuel cells use this type.
- Solid Oxide fuel cells (SOFC) use a hard, ceramic compound of metal (like calcium or zirconium) oxides (O2) as electrolyte. Efficiency is about 60%, and operating temperatures are about 1,000 degrees C (about 1,800 degrees F). Cells output is up to 100 kW. At such high temperatures a reformer is not required to extract hydrogen from the fuel, and waste heat can be recycled to make additional electricity. However, the high temperature limits applications of SOFC units and they tend to be rather large.

The only product available commercially today is the PureCell 200 (formerly PC-25)™ built by UTC Power. It is a PAFC. The cost of the unit is approximately $4,000/kW. The installed cost of the unit approaches $1.1 million. At a rated output of 200kW, this translates to about $5,500/kW, installed. Other fuel cell types are less developed. This information is consistent with that given by DOE which reports the most widely deployed fuel cells cost about $4500/kW [52]. UTC has almost 300 installations worldwide, at places like Walmart, Verizon, and Ritz-Carlton hotels [53].

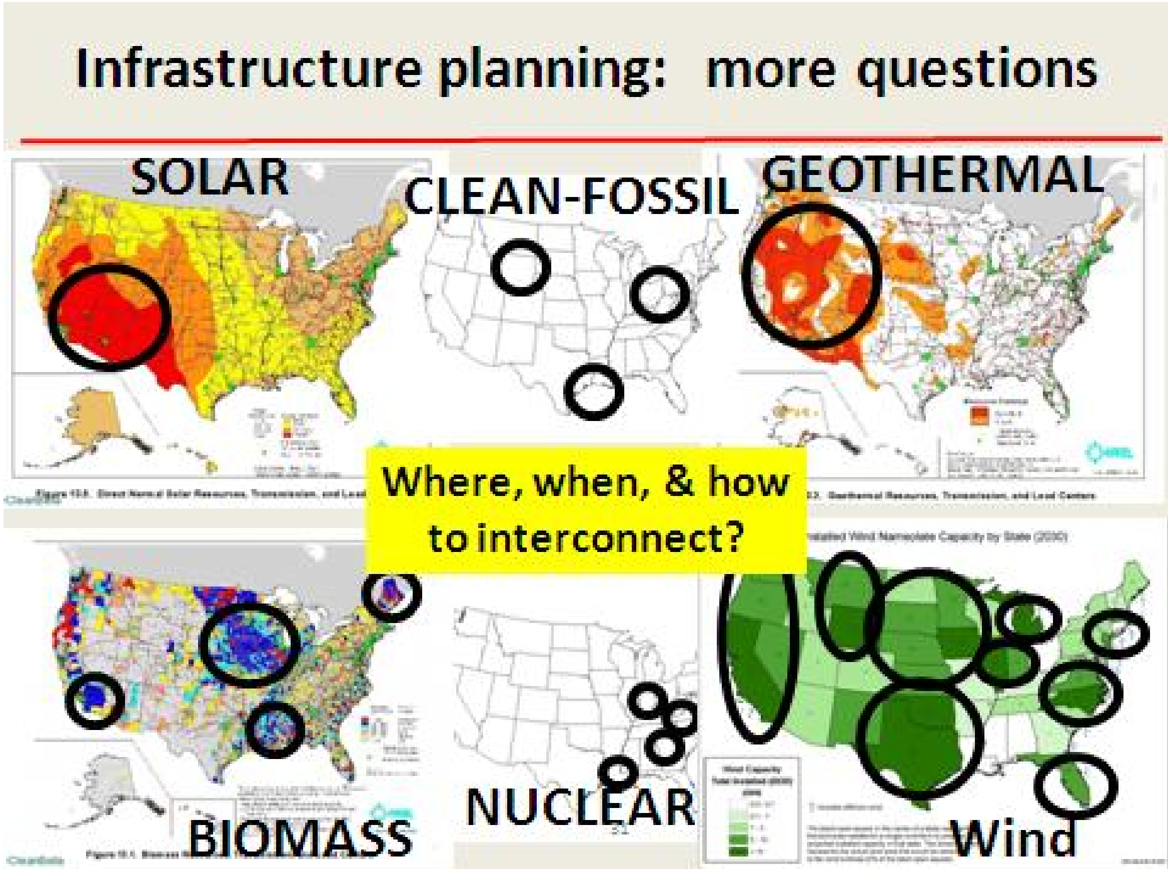
Fuel cells offer interesting opportunities for complementing wind and/or solar energy. Such renewable electrical power can be used in an electrolyser which breaks apart water molecules into hydrogen and oxygen molecules. The hydrogen can be captured and either stored or directly fed into a fuel cell. The advantage of producing hydrogen via electrolysis lies in the fact that over 90% of hydrogen is currently produced from non-renewable sources. The current hydrogen production technology produces CO2 while electrolysis using renewable energy would yield no net CO2 emissions [54]. A commercial system could produce 1000 kg of hydrogen per day. Hydrogen cost with no-cost electricity is $1.50/kg and scales linearly with electricity cost up to $10/kg at $0.14/kWh [55].

Table 6 summarizes these DG technologies [56].

Table 6

Technology	Recip Engine: Diesel	Recip Engine: NG	Microturbine	Combustion Gas Turbine	Fuel Cell
Size	30kW - 6+MW	30kW - 6+MW	30-400kW	0.5 - 30+MW	100-3000kW
Installed Cost ($/kW)[1]	600-1,000	700-1,200	1,200-1,700	400-900	4,000-5,000
Elec. Efficiency (LHV)	30-43%	30-42%	14-30%	21-40%	36-50%
Overall Efficiency[2]	~80-85%	~80-85%	~80-85%	~80-90%	~80-85%
Total Maintenance Costs[3] **($/kWh)**	0.005 - 0.015	0.007-0.020	0.008-0.015	0.004-0.010	0.0019-0.0153
Footprint (sqft/kW)	.22-.31	.28-.37	.15-.35	.02-.61	.9
Emissions (gm / bhp-hr unless otherwise noted)	NO_x: 7-9 CO: 0.3-0.7	NO_x: 0.7-13 CO: 1-2	NO_x: 9-50ppm CO: 9-50ppm	NO_x: <9-50ppm CO:<15-50ppm	NO_x: <0.02 CO: <0.01

Final comment:



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