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Energy Conversion Technologies

Contents:

1.0 Introduction

Interest in and support for a particular power generation technology is subject to multiple influences, including its maturation level, its cost, and its impacts (technical, social, and political), and how federal, state, and local policy-makers perceive these issues relative to their goals. Some examples:

- Wind and solar energy have grown/matured significantly over the past ~20 years, with their maturation fueled by their growth, and their growth fueled by government subsidies.
- Although utility-scale wind and solar in wind and solar-rich regions represent the most economically attractive new power generation technologies today (see LCOE data from Lazard's in the last set of class notes), they generally require relatively hard-to build transmission; in addition, they face growing resistance in the form of county ordinances on setbacks [1].
- Carbon-capture and sequestration (CCS) has had various levels of support over the past 20 years, but it still has not been deployed at a significant level. Most recently, the Environmental Protection Agency (EPA) has proposed a new rule, on "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants," Docket ID No. EPA-HQ- OAR-2023-0072 [2, 3]. Although EPA has legal authority to set carbon pollution standards [4], they asked for comments and received 1,391,230 [5], and both very positive ones [6] as well as highly negative ones [7]. If EPA approves this rule, it will likely stimulate significant CCS deployment and/or accelerate the retirement of fossil-fueled power generation technologies.

- Reference to the latest Lazard's LCOE assessment indicates that offshore wind is significantly more expensive than onshore wind, so much so that multiple studies have shown that it is less expensive to build onshore wind in the Midwest together with long on-shore transmission to the east and west coast load centers than it is to build offshore wind off the east and west coasts and the much shorter offshore transmission to bring it to those same load centers. However, there are two other influences on this issue:
  - *Public resistance*: Although capital and construction costs of onshore transmission are not too high, the public resistance to build onshore transmission is very high, particularly in population-dense regions close to the coasts. It is generally thought that building offshore transmission, despite its own constraints (fisheries, military, existing seabed infrastructure such as oil/gas/cables, nature conservation, and shipping lanes), may face less public resistance than onshore transmission.
  - *Economic development (job creation)*: Almost all publicly elected officials, particularly at the local and state levels, want to be able to create jobs for the population they serve. Building generation resources does exactly this to a significant level, whereas building transmission

does not. Therefore, most elected officials of coastal states typically prefer to build generation within their state rather than import power from other states.

In these notes, we describe the generation and storage technologies available to be considered in the generation planning function. In the first part of these notes, we focus on technologies facilitating conversion of bulk (large) quantities of energy. Towards the end, we describe distributed generation technologies and storage.

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 [8]. (Critical temperature and pressure for water are 705 ºF (374 ºC) and 3210psi (217.7 atm), respectively. When temperature exceeds 705 ºF, and pressure is above these values, water can exist only in the gaseous phase [9].) 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 [10]. 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 coal in the steam generator is passed through an electrostatic precipitator to remove particulate. The flue-gas then passes through a flue-gas desulfurization (FGD) unit (or scrubber[1]), to remove SO_2 from the flue-gas. After scrubbing, the flue-gas is exhausted through a stack. The process is illustrated in Fig. 1.

[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.

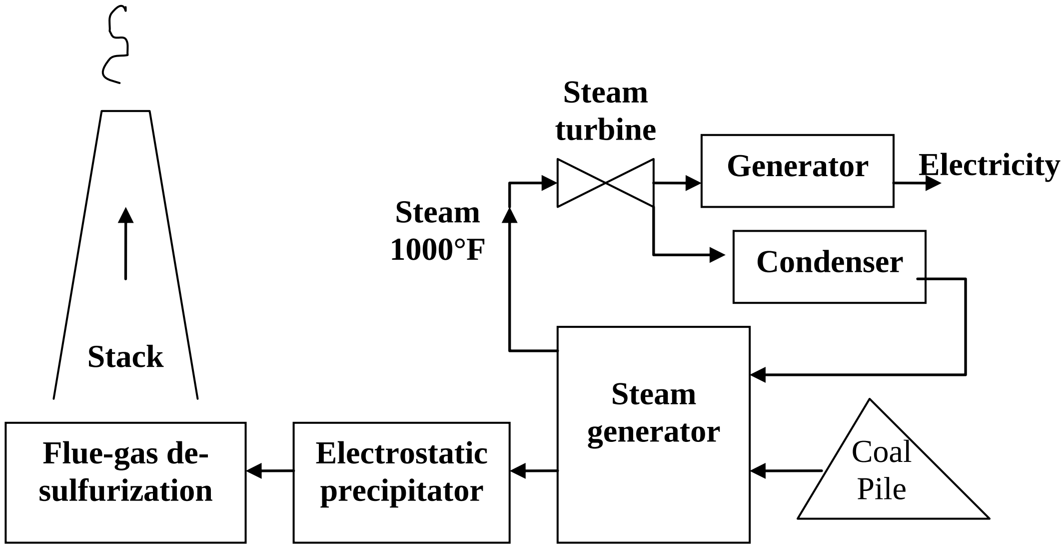


Fig. 1

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.

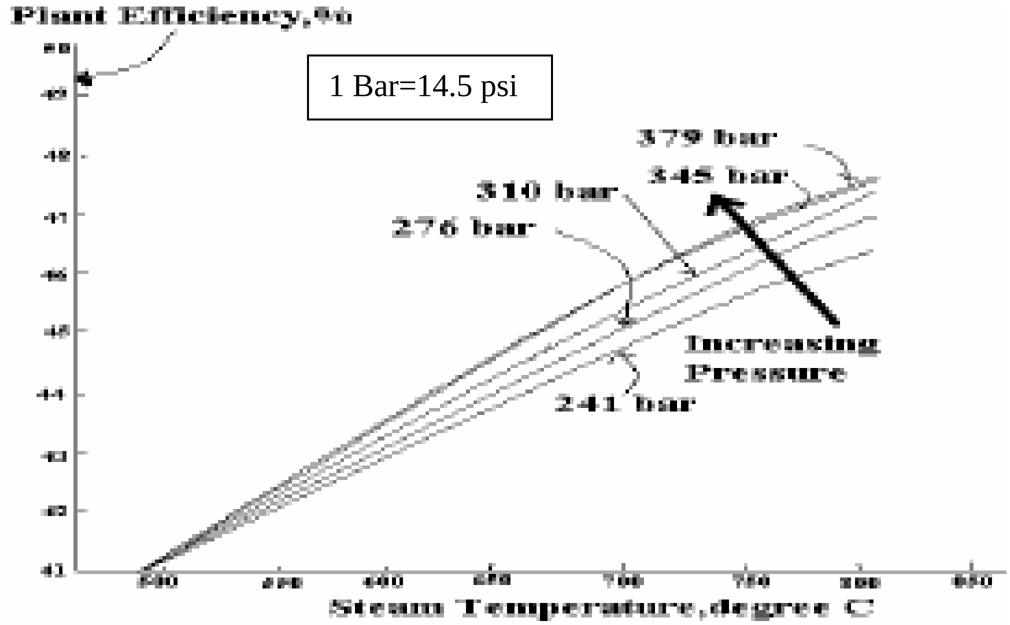


Fig. 3

The sensitivity of Fig. 3 to temperature is important to observe. This is associated with what is referred to as a *cyclic process*, which is a set of changes in the thermodynamic state (temperature, pressure, composition) of a working fluid that culminates in respiration of the fluid to the thermodynamic state from which the changes began. A *heat engine* is a device that converts heat into work by a cyclic process; it is illustrated in Fig. 3a below. Observe that it operates between two different temperatures, T_h and T_c.

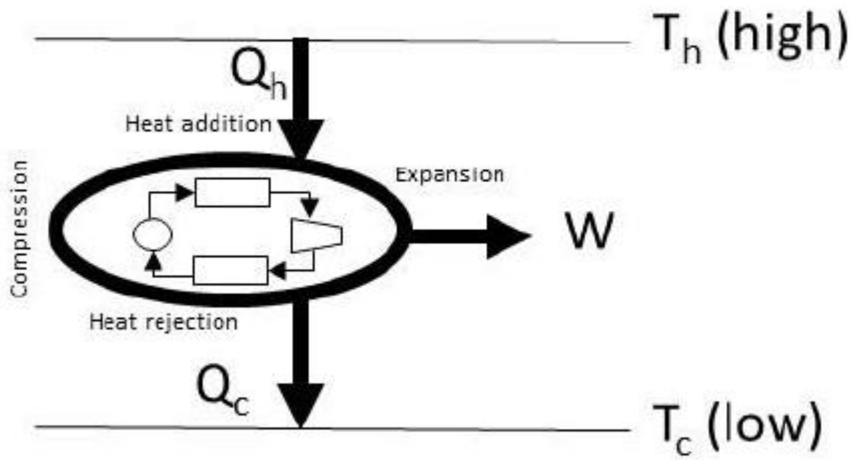


Fig. 3a

The efficiency of a heat engine is given by:

$$\eta_c = \frac{W}{Q_h} = \frac{Q_h - Q_c}{Q_h}$$

A fundamental thermodynamic principle is that heat engine efficiency cannot exceed Carnot efficiency, which can be shown to be dependent on temperatures at which heat is added and rejected, according to:

$$\eta_c = \frac{T_h - T_c}{T_h}$$

For a "single cycle" power plant, maximum efficiency can be estimated based on (a) $T_c \approx 311°K$ (100°F, 38°C), and (b) T_h (corresponding to superheated steam, limited by materials)≈700°K (800°F, 427°C), to give
(700-311)/700=0.56.

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 (in 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 [11]

We also observe from Table X below that investment costs for subcritical and supercritical are similar.

There is only one ultra-supercritical coal plant in the US, the John W. Turk Plant, a 600 MW 40% efficient plant built by AEP in Arkansas [12], becoming operational in 2012, see Fig. 3b. Although it was announced that this plant cost $1.8B ($3000/kw) [13], there is little cost data available for such plants.

Fig. 3b

However, there have been other ultra-supercritical plants built around the world, including [7]:

- Nordjylland Power Station Unit 3 in Denmark, built in 1998. Its electrical efficiency is 47%, but because it operates as a combined heat and power plant (providing district heating to the city of Aalborg), its net efficiency is 91% (i.e., it utilizes 91% of the energy content in the bituminous coals it burns).
- Lunen Plant in North-Rhine Westphalia, Germany, completed in 2013, a 750MW plant, with electrical efficiency of 46%.

- Isogo Thermal Power Station near to Yokohama, Japan, Units 1 and 2, each 600MW, began operations in 2002 and 2009, respectively. Unit 2 has an electrical efficiency of 45%.

The above efficiencies are based on higher heating value (HHV). HHV assumes all the water component is in liquid state at the end of combustion and that heat below 150 °C (302 °F) can be put to use. In contrast, the lower heating value (LHV) is determined by subtracting the heat of vaporization of the water vapor from the HHV. This treats any H_2O formed as a vapor. The energy required to vaporize the water therefore is not released as heat.

Table X

	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	152,975	975,370	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 [14].

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 [14].

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 [15]. 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.

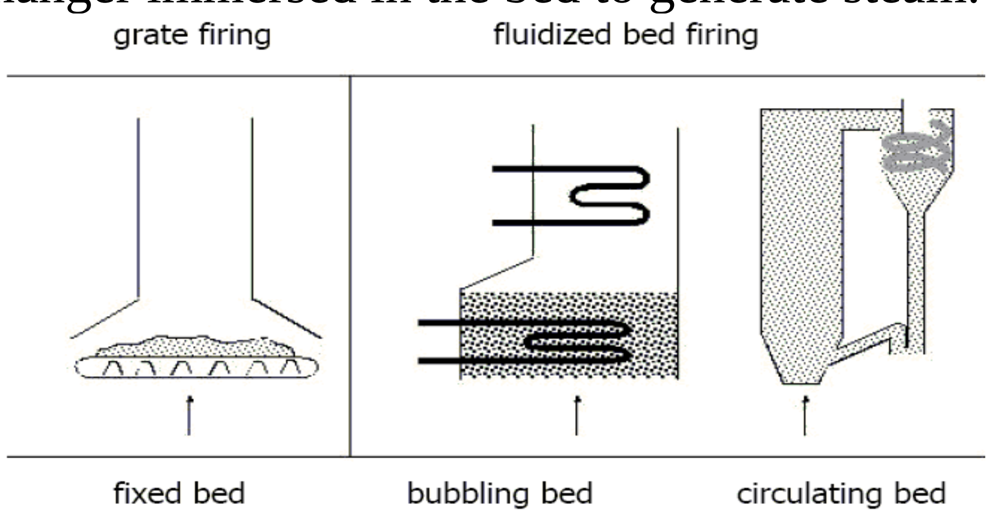


Fig. 4

PFBCs have used both bubbling bed and circulating beds, Fig. 4. In these plants, Fig. 5a [10], 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 [10].

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 Advanced Pressurized Fluidized Bed Combustion Combined Cycle (APFBC) plant [16], 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 [17].

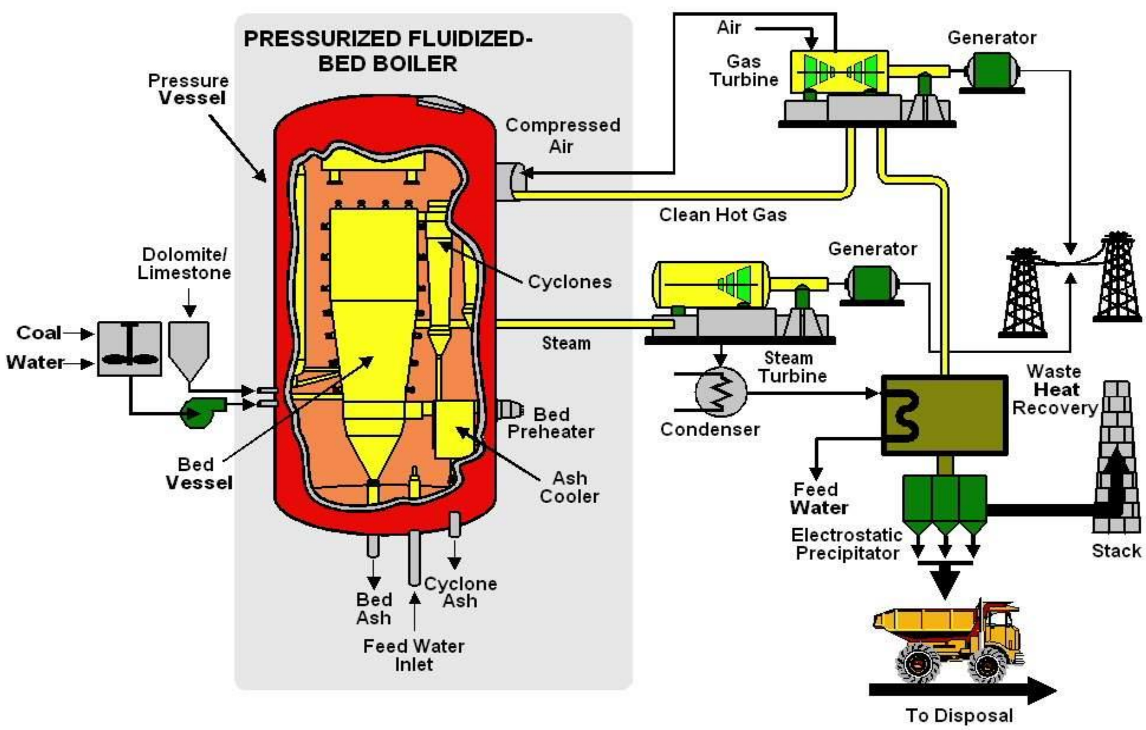


Fig. 5b

Table 1 provides emissions removal rates and other data for several PFBC plants around the world [17].

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 [17] in cents/kWhr.

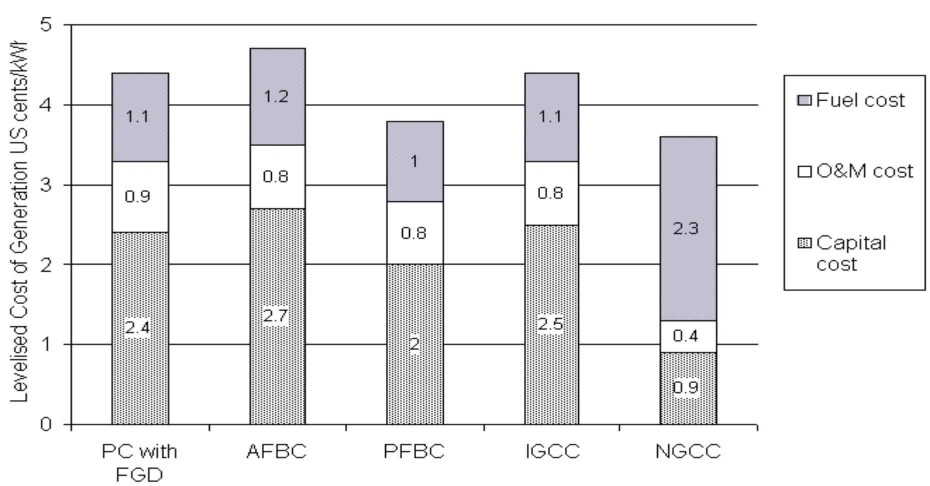


Fig. 6a

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 a later section. The 3 ways are illustrated in Fig. 6b [18].

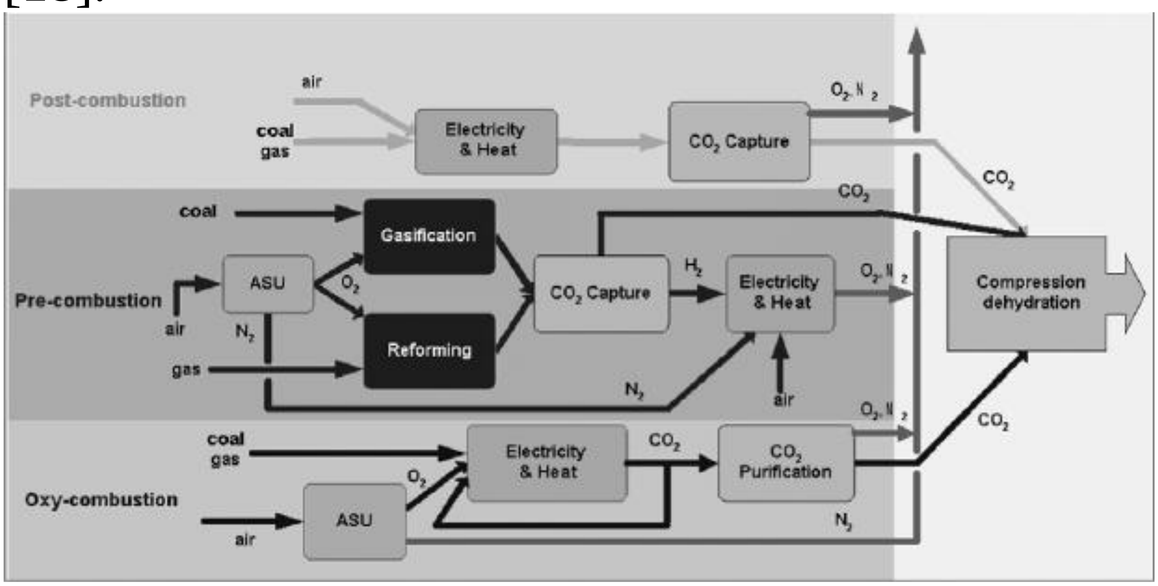


Fig. 6b [18]

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).

In oxycombustion (or O_2-fired combustion), an air-separation unit (ASU) serves to eliminate nitrogen (N_2) from the air to produce the pure oxygen (O_2). The hydrocarbon fuel is combusted with the O_2, rather than air, to produce an exhaust mixture that is mostly CO_2, but with some water vapor [19]. The products of combustion are thus only CO_2 and water vapor. This exhaust mixture has some impurities (O_2 and N_2) which are removed in a purification stage by reducing its temperature to a level at which the CO_2 condenses and the impurities do not. The condensed CO2 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 [19].

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 [19].

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 [19] (2007).

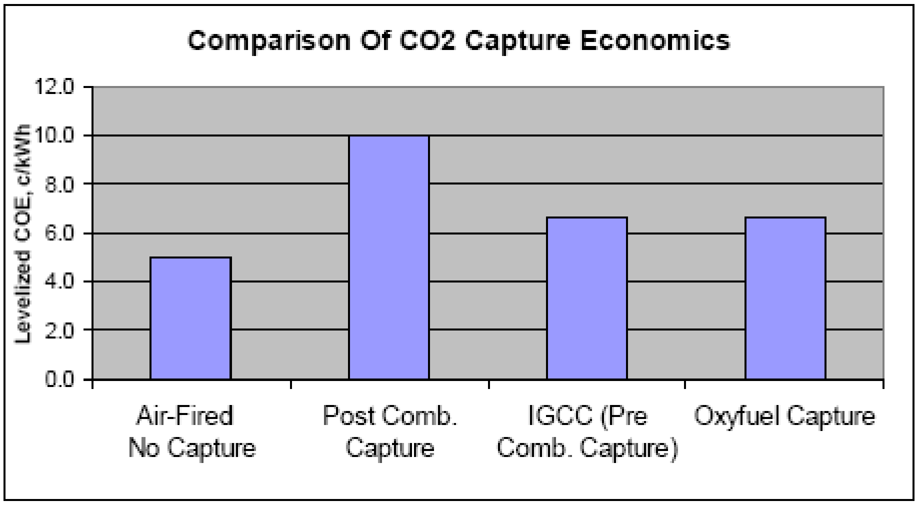


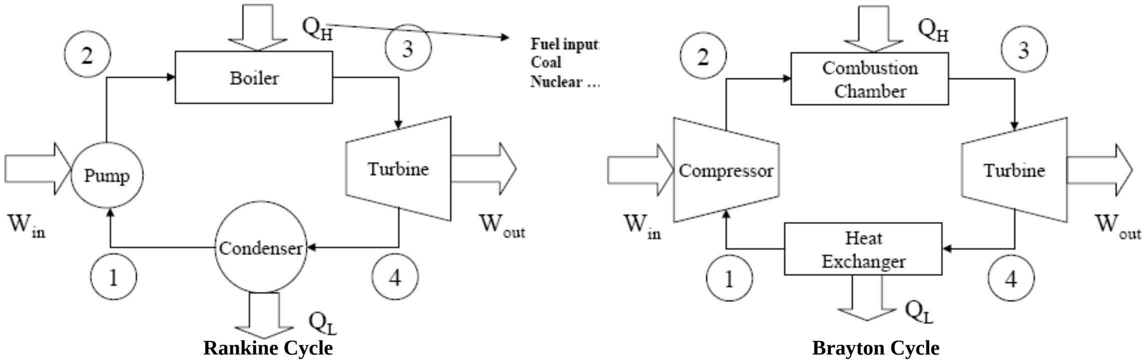
Fig. 7

5.0 Simple Cycle Combustion turbines

Simple cycle combustion turbines (CTs), Fig. 8, [10] 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 [20]. 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.



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 [21].

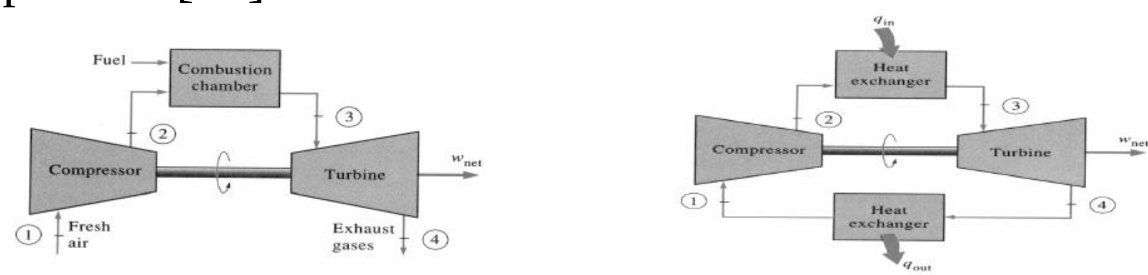


Fig. 9b

6.0 Natural Gas Combined Cycle power plants

Combined cycle combustion turbines [10], 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

Figure 11a [22] illustrates basic functions for a combined cycle power plant.

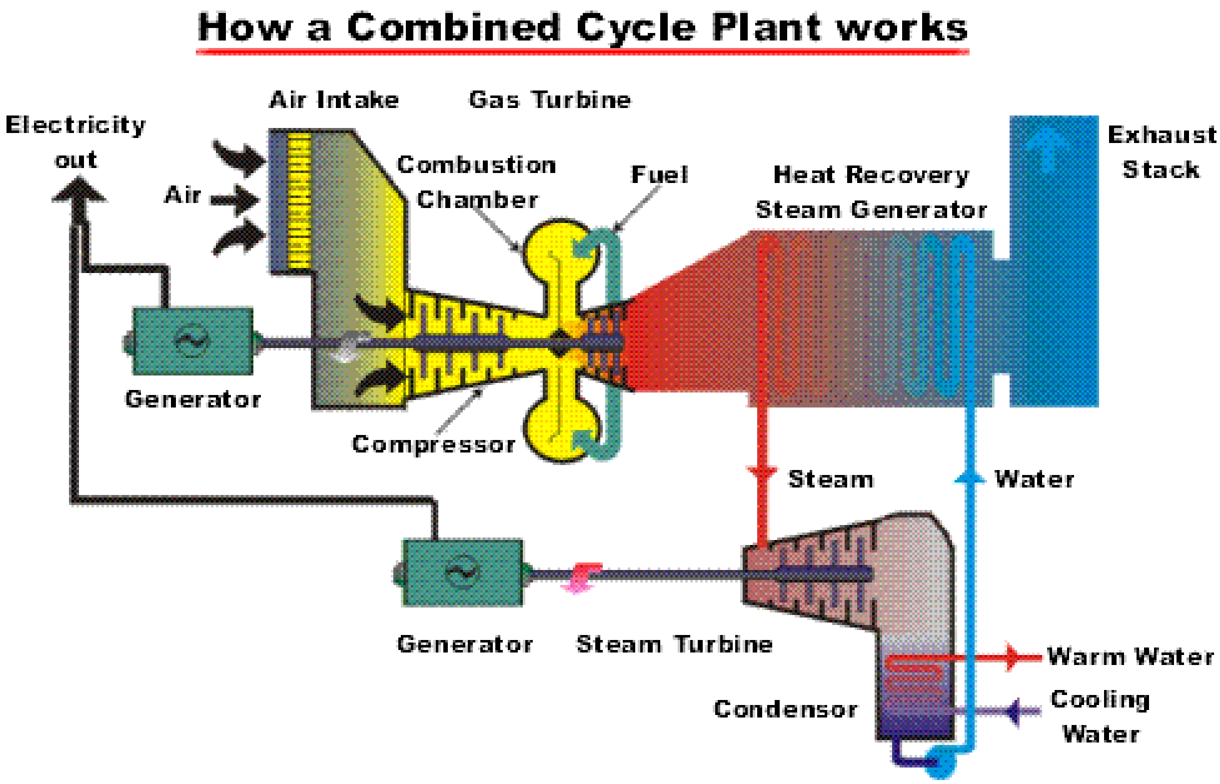


Fig. 11a

Combined cycle plants are so named because they combine the Rankine & Brayton cycles, as shown in Fig. 11b, 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.

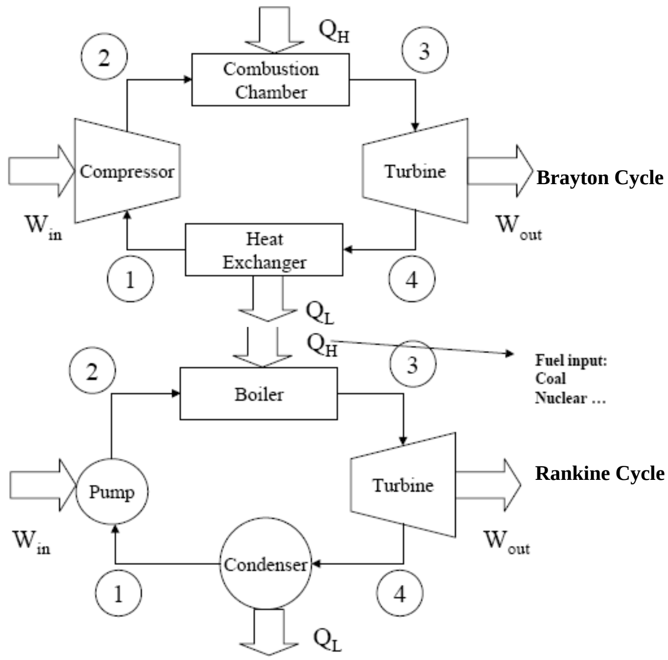


Fig. 11b

The following information was developed from [23, 24, 25]. Figure X1 below shows 2002-2011 US growth in combined cycle power plants [26].

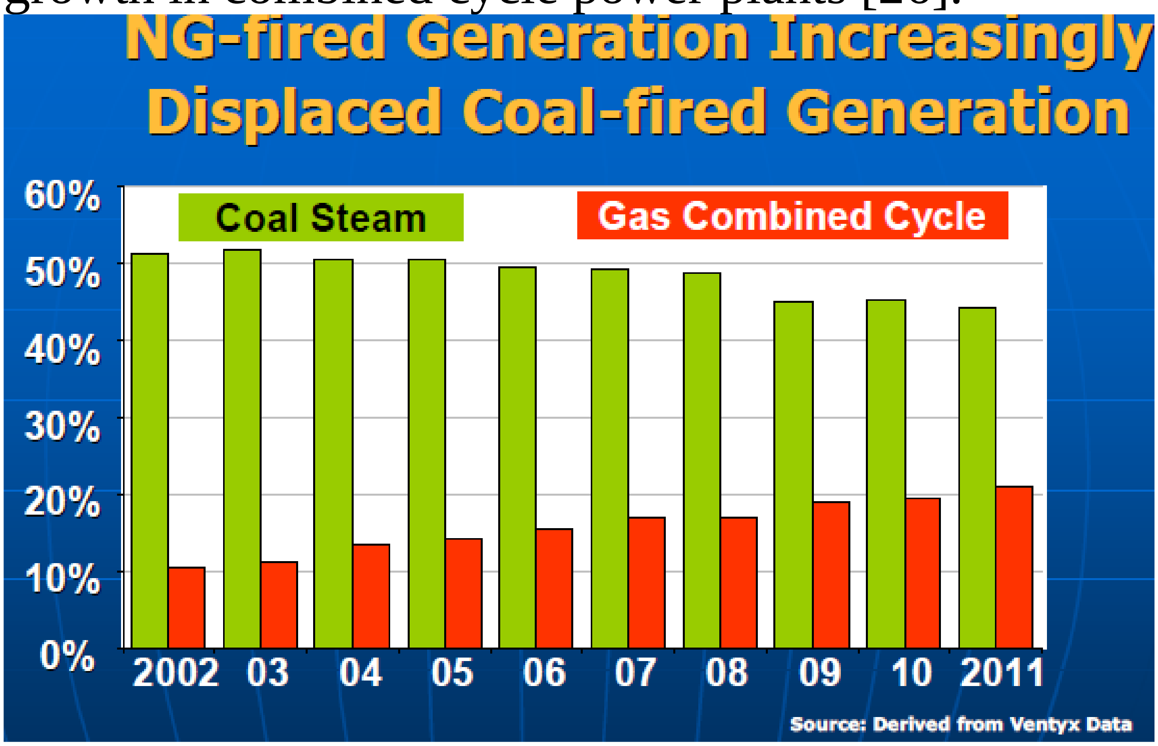


Fig. X1

Figure X2 shows the 2015 indication of “anticipated” or “prospective” US resource growth [27]. Reference [27, Appendix III] provides explicit definitions for these terms; loosely, “anticipated” means “firmly planned” and “prospective” means “tentatively planned.” Note that these are not predictions but rather reflections of planning data from the various planning organizations.

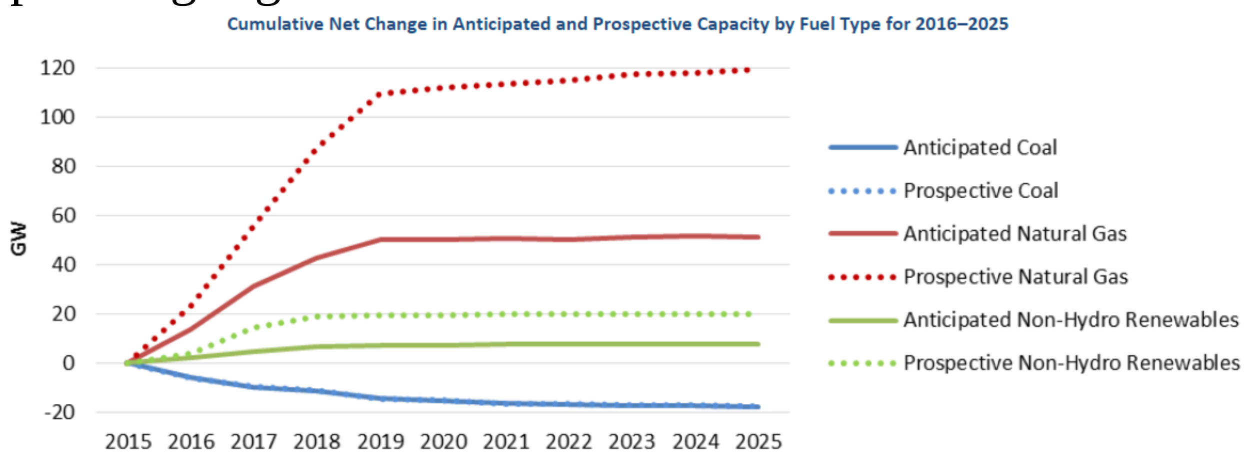


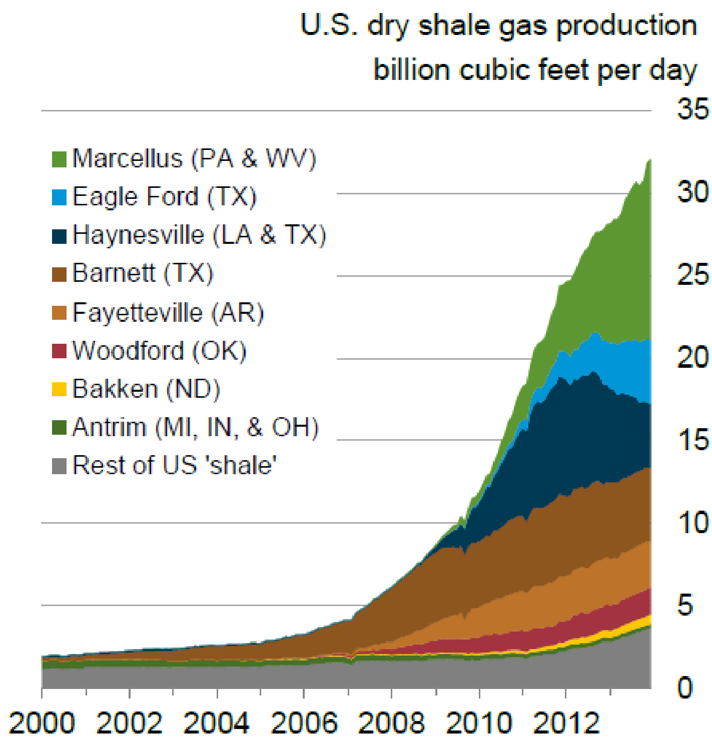
Fig. X2

Although most of the natural gas growth indicated in Fig. X2 is combined cycle, not all is, as some would also be utilized for combustion turbines.

It is interesting that use of gas-fired generation has been increasing during the 1990-2010 period mainly because of the ease of siting and installation of gas-fired generation, high efficiency of combined cycle plants, and understood natural gas prices (stayed pretty stable except for severe winters). It has continued to increase after 2010 and will continue to do so, for these same reasons; there are now the following additional reasons:

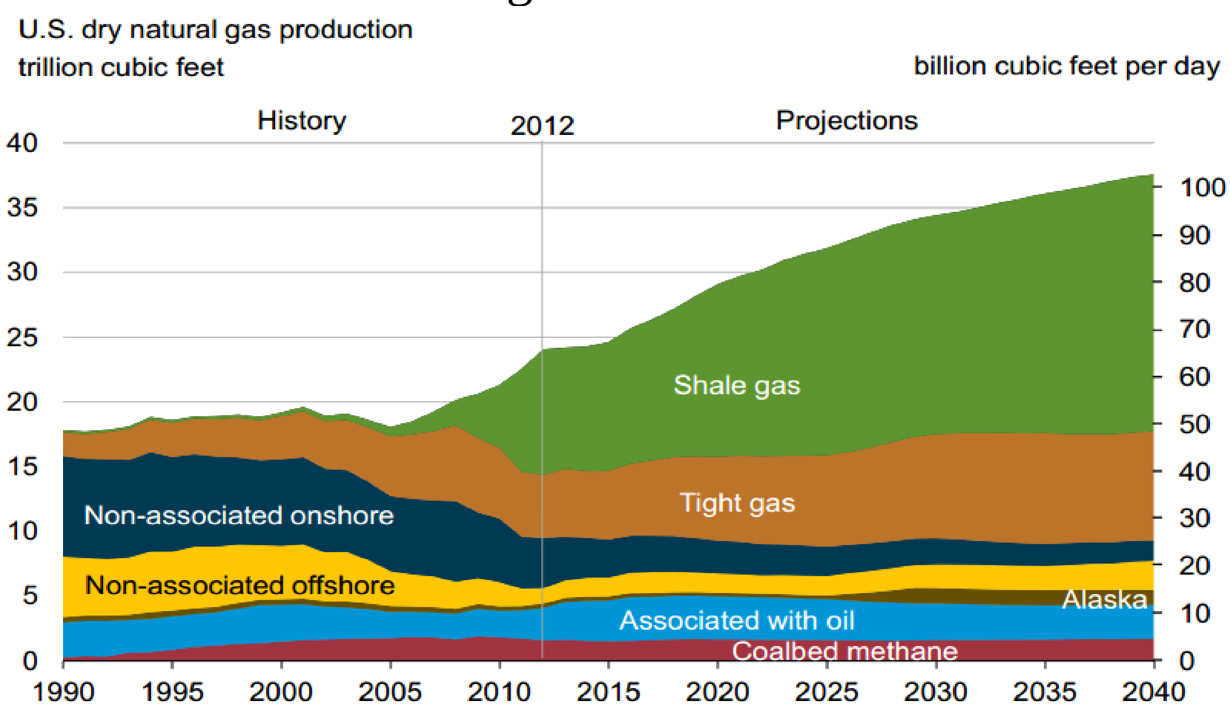
- CO_2 is very important: natural gas has ~half the CO_2 per unit energy content as coal, so using it to replace coal is attractive from a GHG-perspective.
- Gas-fired units are flexible, especially combustion turbines, and high penetration of wind and solar requires such flexibility.
- The supply of natural gas in the US has increased dramatically with the advent of hydraulic fracturing ("fracking") of shale gas, as observed in Fig. X3, which shows which plays contribute the most, and Fig. X4, which shows how much shale gas has and is expected to contribute relative to other forms of gas. Figure X5 shows the location of the relatively new US shale plays. These three figures, X3, X4, and X5-a, were obtained from [28], which is an excellent presentation that is well-worth reviewing to obtain a good understanding of the shale gas/oil situation in the US. Fig. X5-b was obtained from [29]. Some useful description of shale gas terminology is given in Fig. X6 [30], and the hydraulic fracturing process is illustrated in Fig. X7 [31], with potential impacts of hydraulic fracturing indicated in Fig. X8 [31, 32].

More recent gas-electric growth data is provided in notes called "GenerationCosts.pdf."



U.S. dry shale gas production
billion cubic feet per day
Marcellus (PA & WV)
Eagle Ford (TX)
Haynesville (LA & TX)
Barnett (TX)
Fayetteville (AR)
Woodford (OK)
Bakken (ND)
Antrim (MI, IN, & OH)
Rest of US 'shale'
35
30
25
20
15
10
5
0
2000
2002
2004
2006
2008
2010
2012

Fig. X3



U.S. dry natural gas production
trillion cubic feet
billion cubic feet per day
History
2012
Projections
Shale gas
Tight gas
Non-associated onshore
Non-associated offshore
Alaska
Associated with oil
Coalbed methane
40
35
30
25
20
15
10
5
0
100
90
80
70
60
50
40
30
20
10
0
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040

Fig. X4

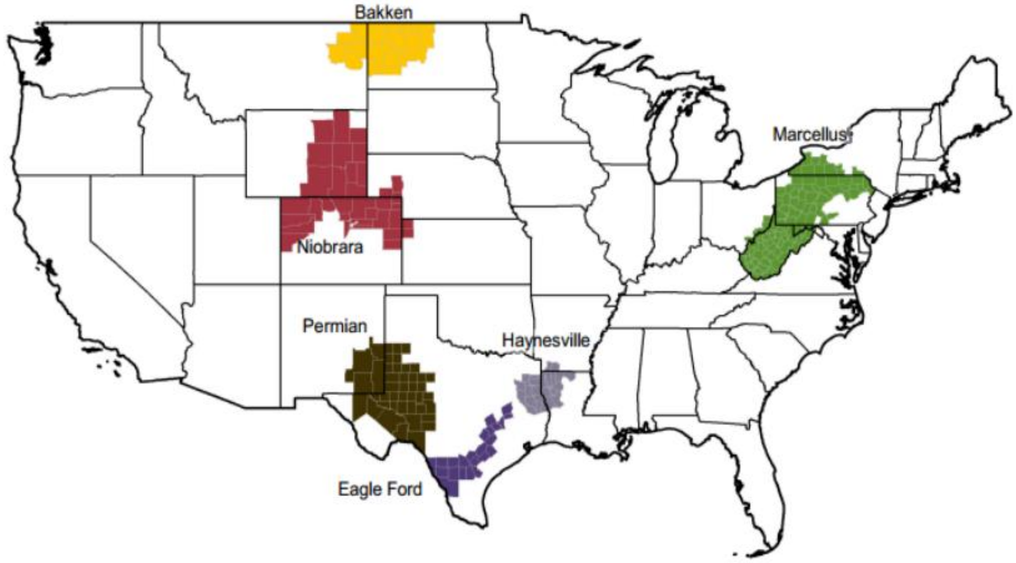


Fig. X5-a

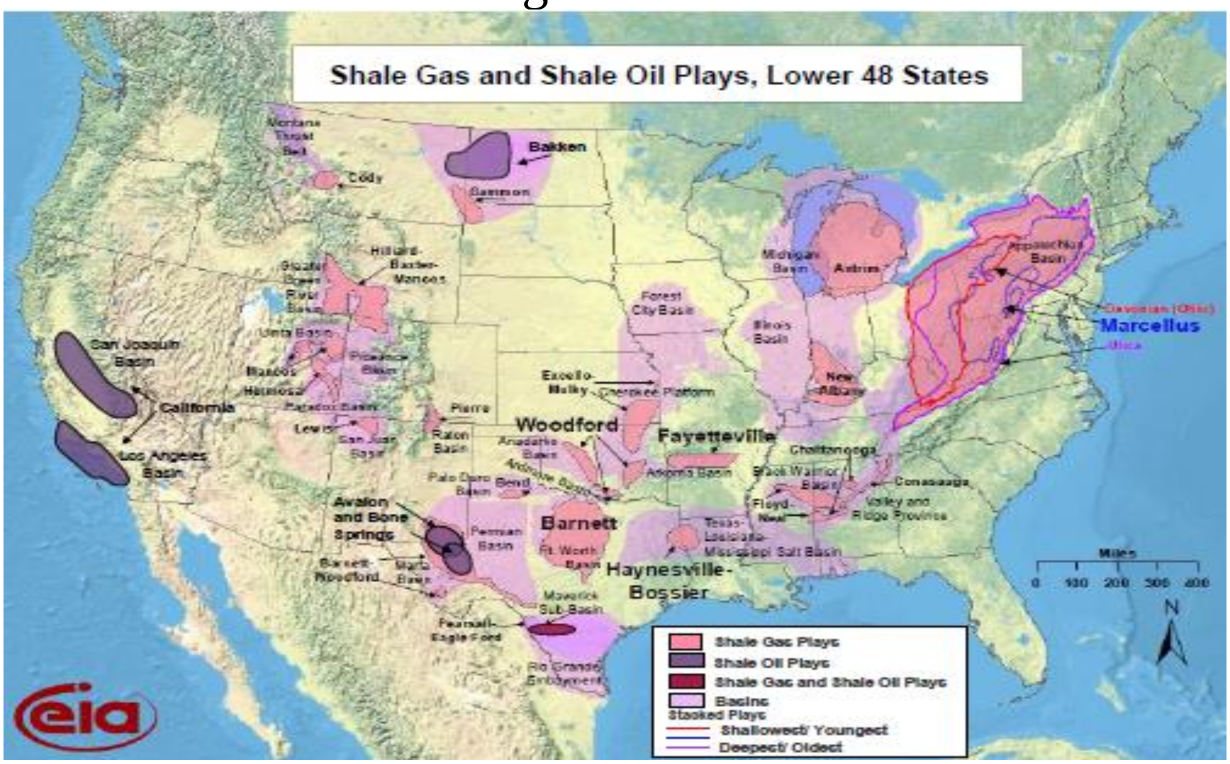


Fig. X5-b

Five shale plays (Eagle Ford, Bakken, Permian for oil, and Marcellus, Haynesville, Eagle Ford for gas) have allowed a rapid increase in natural gas and oil production over the last few years. The Bakken and Eagle Ford plays produce both natural gas & oil, but the oil and gas condensate[2] areas are most attractive today (the oil to gas price ratio is high enough). Eagle Ford contains both natural gas in the southern part of the formation and NGLs/oil in the northern region. This allows operators to move to the most lucrative part of the area depending on the price of commodities. In contrast, most other plays produce either primarily oil (such as Bakken) or gas (such as Barnett).

[2] Condensate is a mix of pentanes and some other heavy hydrocarbons that can be extracted from the gas stream as a liquid at normal pressures and temperatures; normally enters crude oil stream after production.

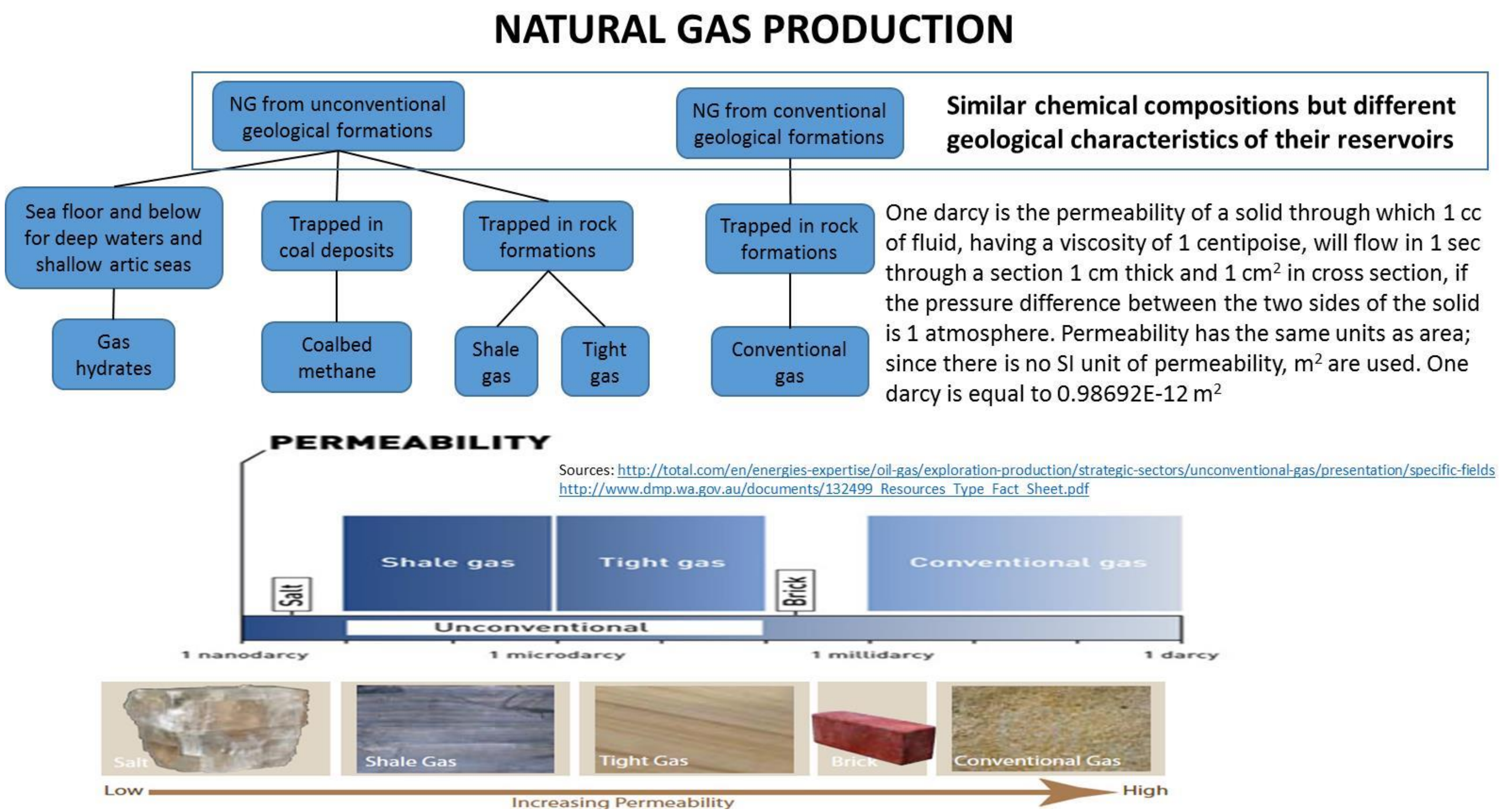
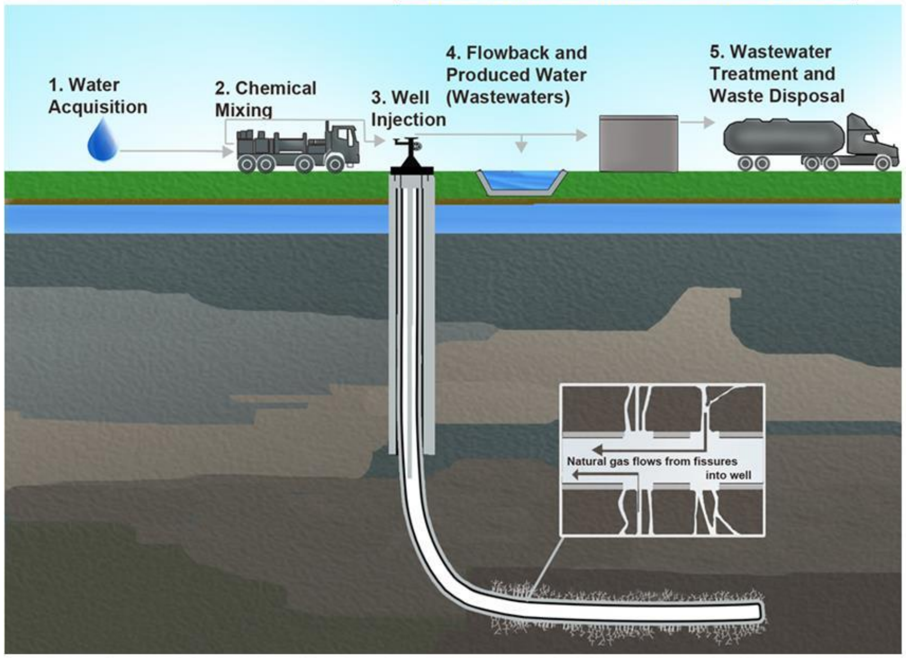

NATURAL GAS PRODUCTION
NG from unconventional geological formations
NG from conventional geological formations
Similar chemical compositions but different geological characteristics of their reservoirs
Sea floor and below for deep waters and shallow artic seas
Trapped in coal deposits
Trapped in rock formations
Trapped in rock formations
Gas hydrates
Coalbed methane
Shale gas
Tight gas
Conventional gas
One darcy is the permeability of a solid through which 1 cc of fluid, having a viscosity of 1 centipoise, will flow in 1 sec through a section 1 cm thick and 1 cm² in cross section, if the pressure difference between the two sides of the solid is 1 atmosphere. Permeability has the same units as area; since there is no SI unit of permeability, m² are used. One darcy is equal to 0.98692E-12 m²
PERMEABILITY
Sources: http://total.com/en/energies-expertise/oil-gas/exploration-production/strategic-sectors/unconventional-gas/presentation/specific-fields
http://www.dmp.wa.gov.au/documents/132499_Resources_Type_Fact_Sheet.pdf
Salt
Shale gas
Tight gas
Brick
Conventional gas
Unconventional
1 nanodarcy
1 microdarcy
1 millidarcy
1 darcy
Salt
Shale Gas
Tight Gas
Brick
Conventional Gas
Low
Increasing Permeability
High

Fig. X6

Hydraulic Fracturing Process

Source: http://www2.epa.gov/hfstudy/hydraulic-fracturing-water-cycle



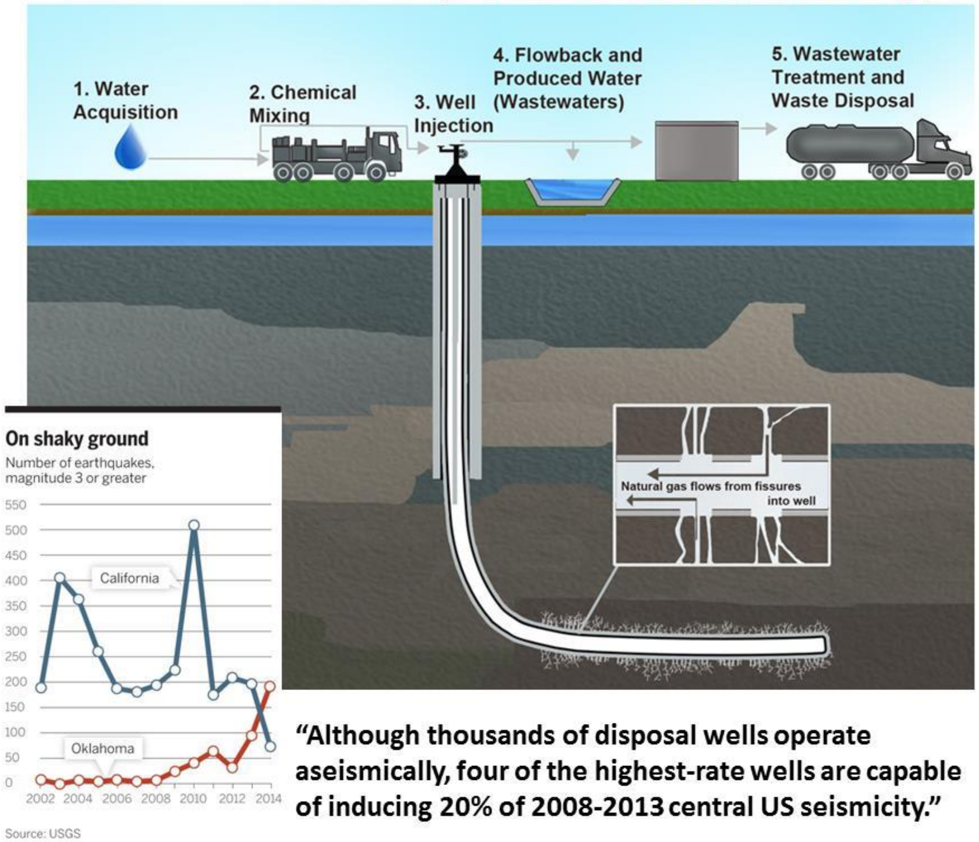
PROCESS

Water Acquisition	Large volumes of water are withdrawn from ground water [2] and surface water [3] resources to be used in the hydraulic fracturing process
Chemical Mixing	Once delivered to the well site, the acquired water is combined with chemical additives [4] and proppant[5] (sand) to make the hydraulic fracturing fluid.
Well Injection	Pressurized hydraulic fracturing fluid is injected into the well, creating cracks in the geological formation that allow oil or gas to escape through the well to be collected at the surface.
Flowback and Produced Water	When pressure in the well is released, hydraulic fracturing fluid, formation water, and natural gas begin to flow back up the well. This combination of fluids, containing hydraulic fracturing chemical additives and naturally occurring substances, must be stored on-site—typically in tanks or pits—before treatment, recycling, or disposal.
Wastewater Treatment and Waste Disposal	Wastewater is dealt with in one of several ways, including but not limited to: disposal by underground injection, treatment followed by disposal to surface water bodies, or recycling (with or without treatment) for use in future hydraulic fracturing operations.

Fig. X7

Hydraulic Fracturing & seismic/water impacts

Source: http://www2.epa.gov/hfstudy/hydraulic-fracturing-water-cycle



"Although thousands of disposal wells operate aseismically, four of the highest-rate wells are capable of inducing 20% of 2008-2013 central US seismicity."

Source: K . Keranen, M. Weingarten, G. Abers, B. Bekins, & S. Ge, **Sharp increase in central Oklahoma seismicity since 2008 induced by massive wastewater injection** Science , 3 July 2014

WATER IMPACTS

Water Acquisition	-Change in the quantity of water available for drinking. -Change in drinking water quality
Chemical Mixing	Release to surface and ground water through on-site spills and/or leaks
Well Injection	-Release of hydraulic fracturing fluids to ground water due to inadequate well construction or operation. -Movement of hydraulic fracturing fluids from the target formation to drinking water aquifers through local man-made or natural features -Movement into drinking water aquifers of natural substances found underground, such as metals or radioactive materials, which are mobilized during hydraulic fracturing activities.
Flowback and Produced Water	Release to surface or ground water through spills or leakage from on-site storage
Wastewater Treatment and Waste Disposal	-Contaminants reaching drinking water due to surface water discharge and inadequate treatment of wastewater -Byproducts formed at drinking water treatment facilities by reaction of hydraulic fracturing contaminants with disinfectants

The United States Environmental Protection Agency is developing a study to look at potential impacts of hydraulic fracturing at each stage of the cycle.

Fig. X8

Combined cycle units utilize both gas turbines (based on the Brayton cycle) and steam turbines (based on the Rankine cycle). Gas turbines are very similar to jet engines where fuel (can be either liquid or gas) mixed with compressed air is ignited. The combustion increases the temperature and volume of the gas flow, which when directed through a valve-controlled nozzle over turbine blades, spins the turbine which drives a synchronous generator. On the other hand, steam turbines utilize a fuel (coal, natural gas, petroleum, or uranium) to create heat which, when applied to a boiler, transforms water into high pressure superheated (above the temperature of boiling water) steam. The steam is directed through a valve-controlled nozzle over turbine blades, which spins the turbine to drive a synchronous generator.

A combined cycle power plant combines gas turbine (also called combustion turbine) generator(s) with turbine exhaust waste heat boiler(s) (also called heat recovery steam generators or HRSG) and steam turbine generator(s) for the production of electric power. The waste heat from the combustion turbine(s) is fed into the boiler(s) and steam from the boiler(s) is used to run steam turbine(s). Both the combustion turbine(s) and the steam turbine(s) produce electrical energy. Generally, the combustion turbine(s) can be operated with or without the boiler(s).

A combustion turbine is also referred to as a simple cycle gas turbine generator. They are relatively inefficient with net heat rates at full load of some plants at 15 MBtu/MWhr, as compared to the 9.0 to 10.5 MBtu/MWhr heat rates typical of a large fossil fuel fired utility generating station. This fact, combined with what can be high natural gas prices, make the gas turbine expensive. Yet, they can ramp up and down very quickly, so as a result, combustion turbines have mainly been used only for peaking or standby service.

The gas turbine exhausts relatively large quantities of gases at temperatures over 900 °F. In combined cycle operation, then, the exhaust gases from each gas turbine will be ducted to a waste heat boiler. The heat in these gases, ordinarily exhausted to the atmosphere, generates high pressure superheated steam. This steam will be piped to a steam turbine generator. The resulting combined cycle heat rate is in the 7.0 to 9.5 MBtu/MWhr range, significantly less than a simple cycle gas turbine generator.

In addition to the good heat rates, combined cycle units have flexibility to utilize different fuels (natural gas, heavy fuel oil, low Btu gas, coal-derived gas) [33]. (In fact, as discussed in Section 7, there are some advanced technologies, including the *integrated gasification combined cycle* (IGCC) plant, which make it possible to run combined cycle on solid fuel (e.g., coal or biomass) [34]).

The flexibility of combined cycle plants, together with the fast ramp rates of the combustion turbines and relatively low heat rates, has made the combined cycle unit the unit of choice for a large percentage of recent new power plant installations. The potential for increased gas supply and lowered gas prices has further stimulated this tendency.

Fig. 32 shows the simplest kind of combined cycle arrangement, where there is one combustion turbine and one HRSG driving a steam turbine.

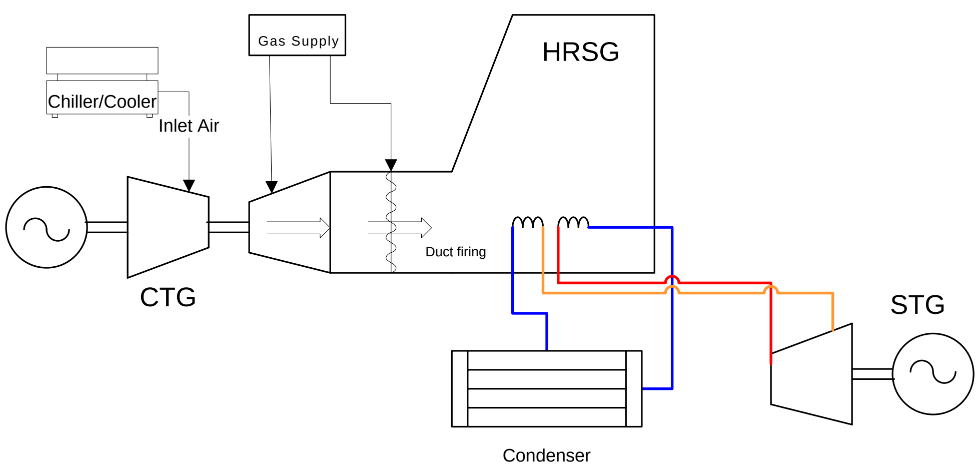


Fig. 32: A 1 × 1 configuration

An additional level of complexity would have two combustion turbines (CT A and B) and their HRSGs driving one steam turbine generator (STG), as shown in Fig. 33.

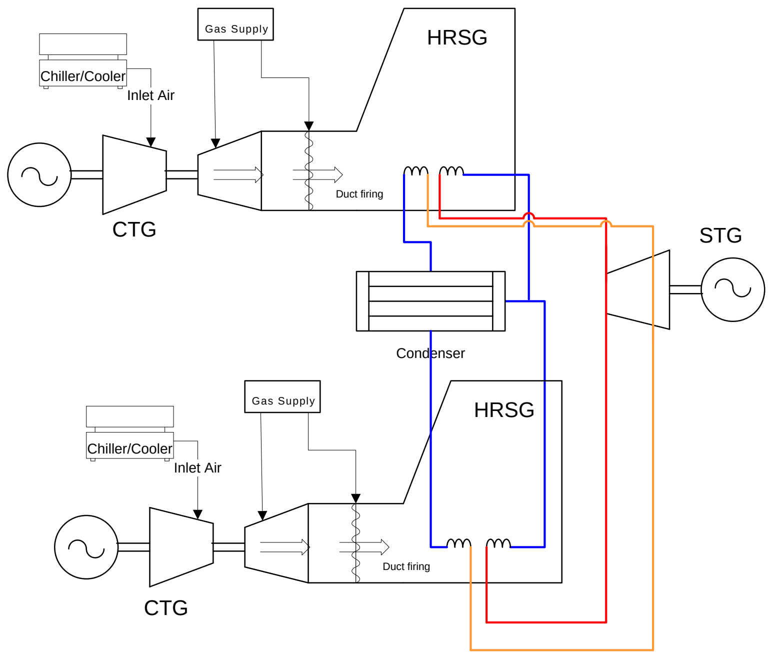


Fig. 33: a 2 × 1 configuration

In such a design, the following six combinations are possible.

- CT A alone
- CT B alone
- CT A and CT B together
- CT A and STG
- CT B and STG
- CT A and B and STG

The modes with the STG are more efficient than the modes without the STG (since the STG utilizes CT exhaust heat that is otherwise wasted), with the last mode listed being the most efficient.

7.0 Integrated gasification combined cycle, IGCC

The first two operational IGCC plants in the US were the Polk Station Plant in Tampa and the Wabash River Plant in Indiana [35]. Figure 12 shows the Wabash River, Indiana IGCC.

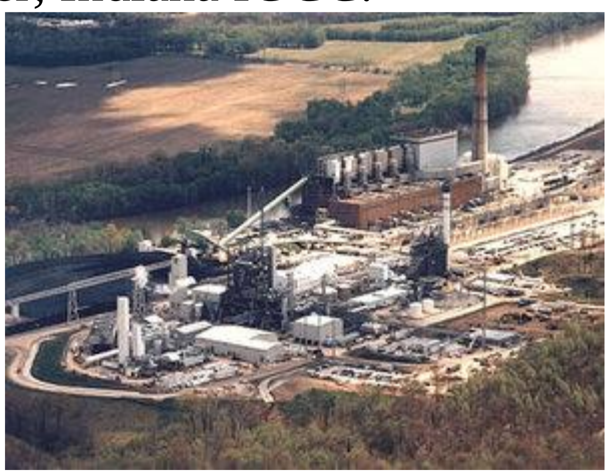


Fig. 12

The Ratcliffe-Kemper plant, owned by Mississippi Power (a subsidiary of Southern Company), was intended to be a 582 MW IGCC plant completed in 2014 [36, 37] but has seen significant cost increases and delays [38]. It is now operated as an NGCC. A recently opened IGCC plant owned by Duke Energy, called Edwardsport, has also experienced outages and maintenance issues [38]. A 300 MW IGCC plant in Kern Country, California that converts coal and petroleum coke into electricity, hydrogen energy, and fertilizer, is called the Hydrogen Energy California polygeneration clean coal plant. DOE decided to suspend funding for this plant [38].

Figs. 13a [39], 13b [40], and 13c [41] illustrate an IGCC unit.

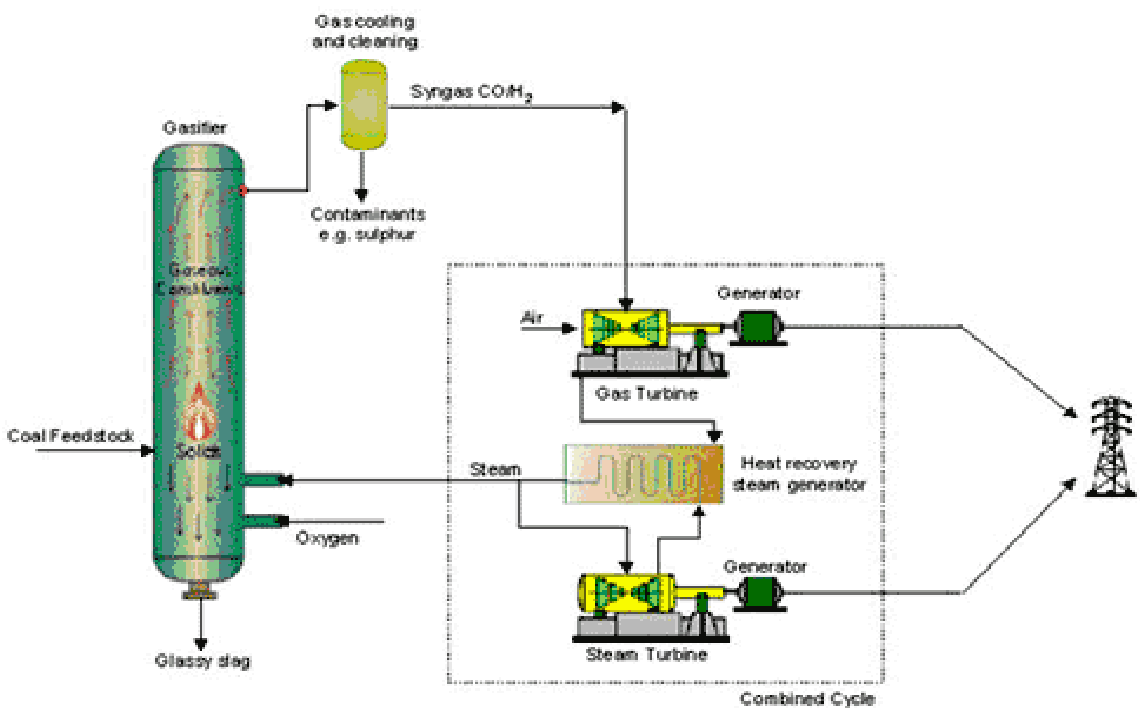


Fig. 13a

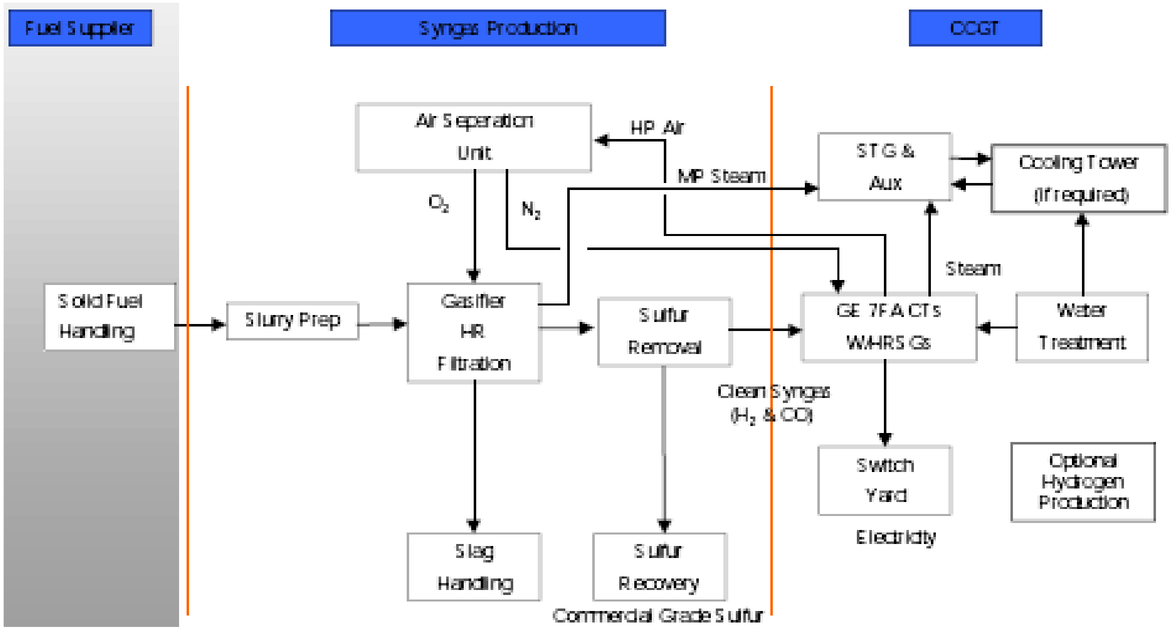

Fuel Supplier
Syngas Production
CCGT
Air Separation Unit
HP Air
MP Steam
O_2
N_2
STG & Aux
Cooling Tower (If required)
Steam
Solid Fuel Handling
Slurry Prep
Gasifier HR Filtration
Sulfur Removal
GE 7FA CTs W/HRSGs
Water Treatment
Clean Syngas (H_2 & CO)
Switch Yard
Optional Hydrogen Production
Electricity
Slag Handling
Sulfur Recovery
Commercial Grade Sulfur

Fig. 13b

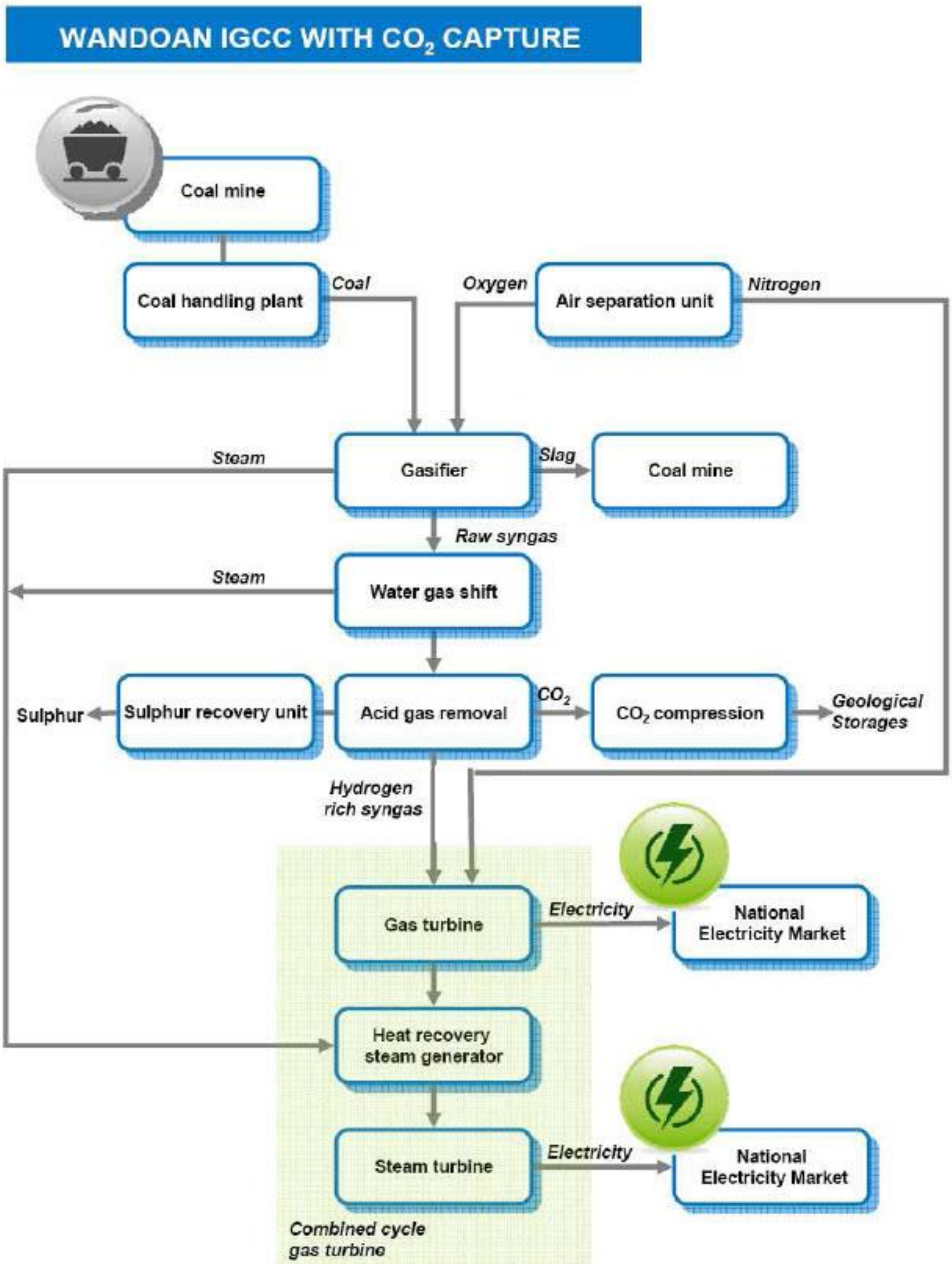

WANDOAN IGCC WITH CO_2 CAPTURE
Coal mine
Coal handling plant
Coal
Oxygen
Air separation unit
Nitrogen
Steam
Gasifier
Slag
Coal mine
Raw syngas
Steam
Water gas shift
Sulphur
Sulphur recovery unit
Acid gas removal
CO_2
CO_2 compression
Geological Storages
Hydrogen rich syngas
Gas turbine
Electricity
National Electricity Market
Heat recovery steam generator
Steam turbine
Electricity
National Electricity Market
Combined cycle gas turbine

Fig. 13c

In IGCC,

- 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 and CO.
- The gas is cooled and CO_2 can be captured via chemical absorption. This is an advantage in that this pre-combustion process is much less expensive in comparison to 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 may proliferate.

Do not confuse oxy-combustion with IGCC:

- In oxy-combustion, the coal itself is still combusted, whereas in IGCC, the coal is converted to syngas before it is combusted.
- In oxy-combustion, the actual CO_2 capture is performed post-combustion (but is not named "post-combustion" to allow use of that term for the process whereby solvents (amines) absorb the CO_2 from the flue-gas); the oxy-combustion exhaust is mostly CO_2 so that CO_2 capture is a purification stage. In contrast, IGCC is a process that converts coal to gas. That in itself significantly decreases SO_2, NOx, and Hg, but it does not decrease the CO_2. CO_2 capture from IGCC is, however, a very mature technology based on its use in the chemical industry. Here, a "water-shift-reaction" is used whereby CO and water react to form CO2 and H2.

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.

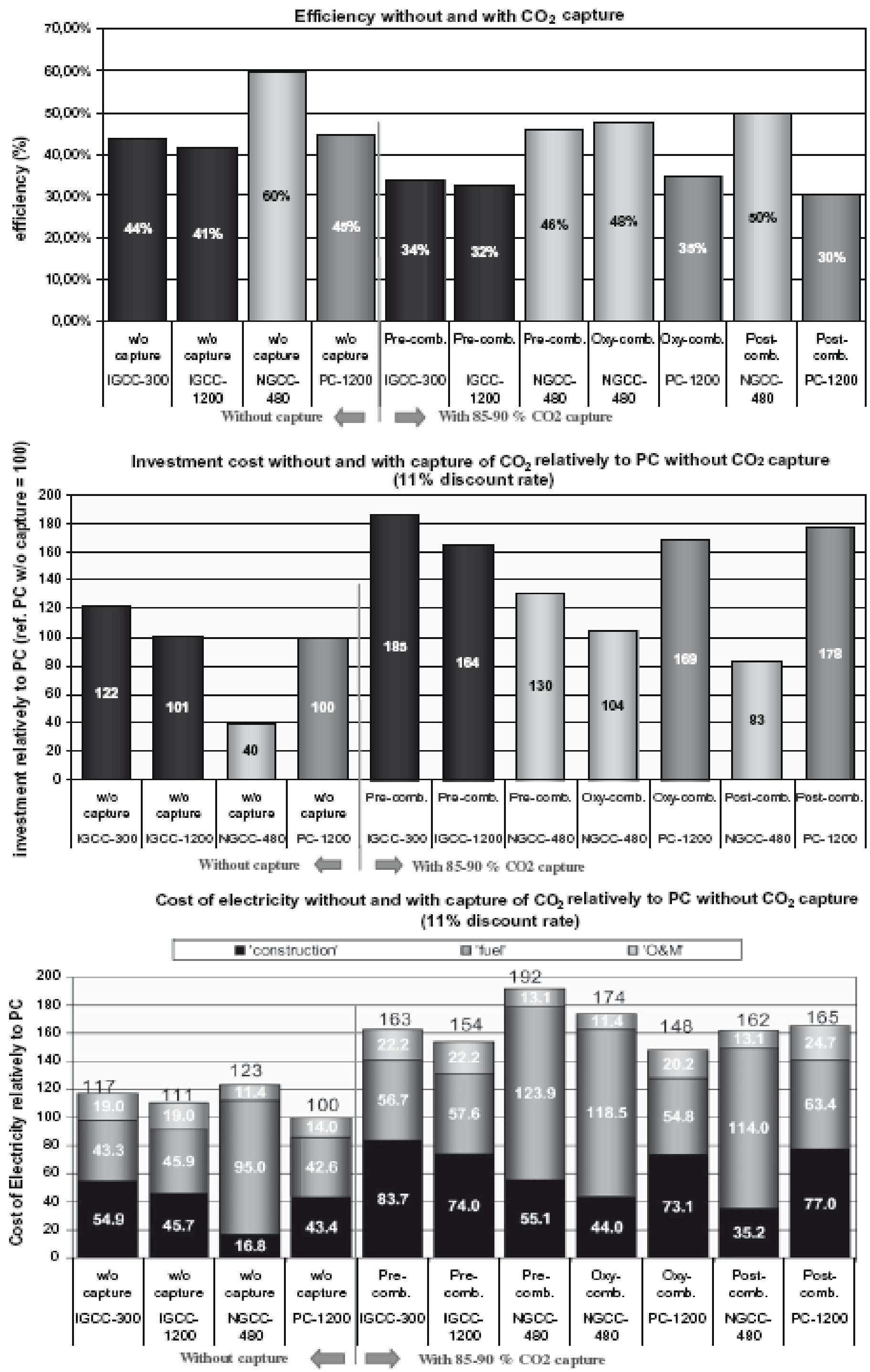
There is some indication that IGCC's compare favorably with other coal-fired generation technologies, as indicated in Table 2. However, this is relatively old information, and more current information may indicate otherwise.

Table 2: 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 waste (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 [42]. Even with CO2 sequestration in typical coal or NGCC setups, a BIGCC plant without CO2 sequestration has better GHG reduction. One reference indicates that the cost of electricity from BIGCC at 600 MW scale will be 5.5¢/kWh; PC and NGCC both with CO2 sequestration will be 7.3¢/kWh & 7.5¢/kWh, respectively.

Other data comparing IGCCs and traditional plants is in a 2010 document [18]. Fig. 13c shows results from this study comparing efficiency, investment cost, and LCOE.



Efficiency without and with CO_2 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 CO_2 relatively to PC without CO_2 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
178
83
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 CO_2 relatively to PC without CO_2 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
19.0
43.3
54.9
111
19.0
45.9
45.7
123
11.4
95.0
16.8
100
14.0
42.6
43.4
163
22.2
56.7
83.7
154
22.2
57.6
74.0
192
13.1
123.9
55.1
174
11.4
118.5
44.0
148
20.2
54.8
73.1
162
13.1
114.0
35.2
165
24.7
63.4
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 was dormant between one unit that came on-line in 1996 (Watts Bar, Tennessee), another unit to come on-line in 2016 at the same location; two units began in 2013 at Plant Vogtle, Georgia; unit 3 came on-line in July 2023, and unit 4 is scheduled to come on-line about 6/2024. Fig. N-1 illustrates number of US reactors 1973-2004 (identifying splits between PWR & BWR); Fig. N-2 shows these numbers from 1957-2022 [43].

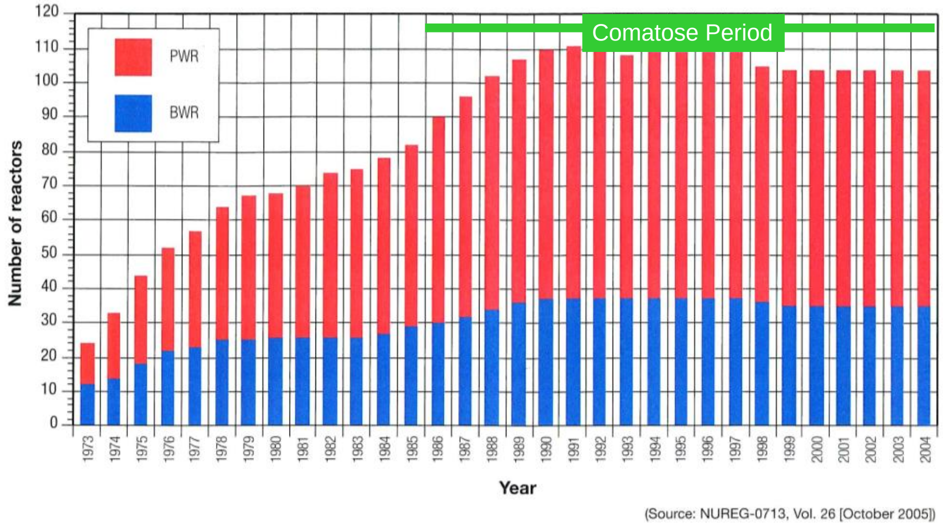


Fig. N-1: Number of US Operating Reactors ‘73-‘04

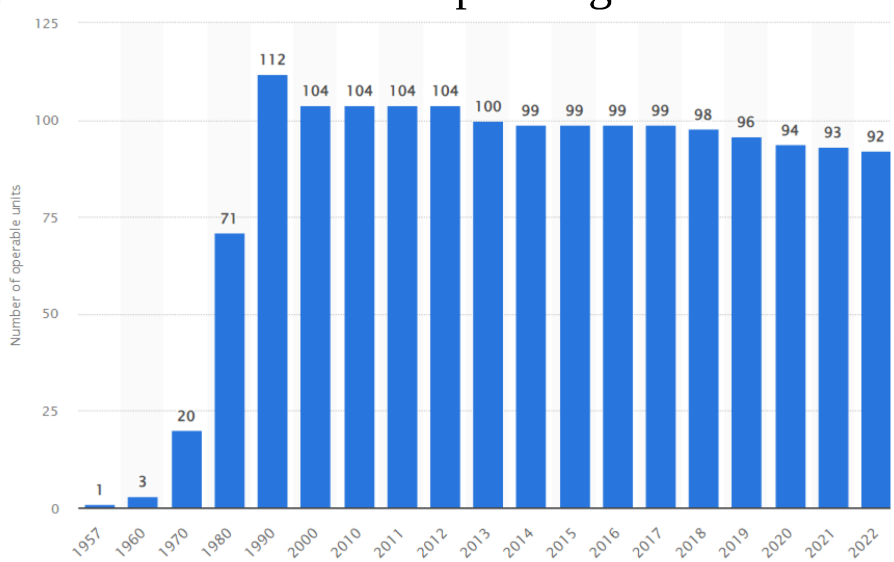


Fig. N-2: Number of US Operating Reactors ‘57-‘22

Fig. N-3 illustrates nuclear growth between 1957-2022 in terms of capacity (in GW on left axis) and energy (in GW-hr, on right axis). One observes that while capacity has been declining over the last 15 years, energy has been holding fairly constant, an indication that the average capacity factors of nuclear plants have been increasing.

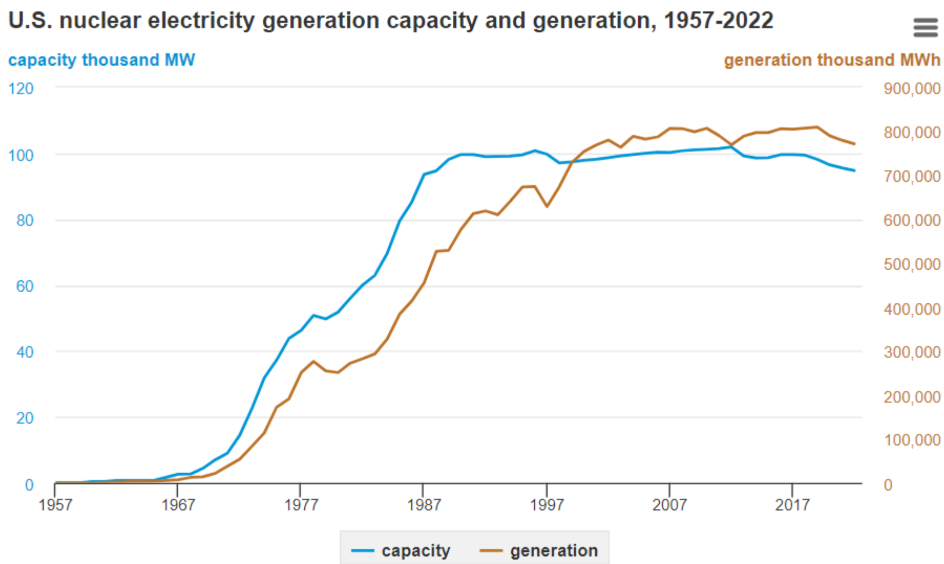


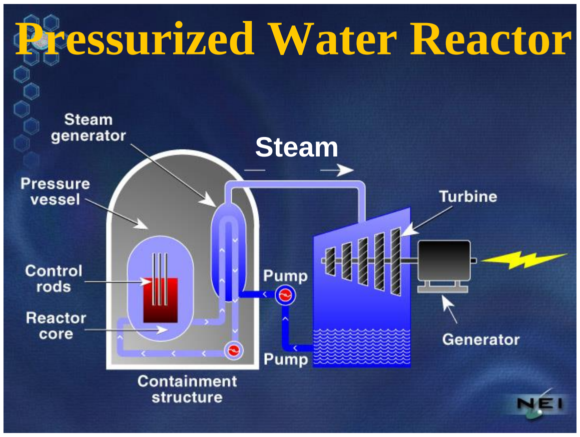
Fig. N-3: Number of US Operating Reactors ‘57-‘22

If we assume a 50-year life on these plants, and noting that over half the plants were operating by 1978, almost all by 1990, we will lose half of this resource by 2028 and almost all of it by 2038, if additional nuclear plants are not built.

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

Nuclear technology

As indicated in Fig. N-4, 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 neutrons released from fission to a speed or energy level to cause further fission & sustain the reaction.



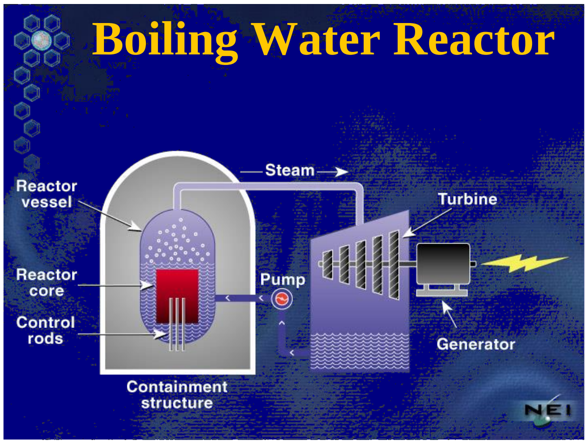


Fig. N-4

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 produce 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. N-5, are PWR.

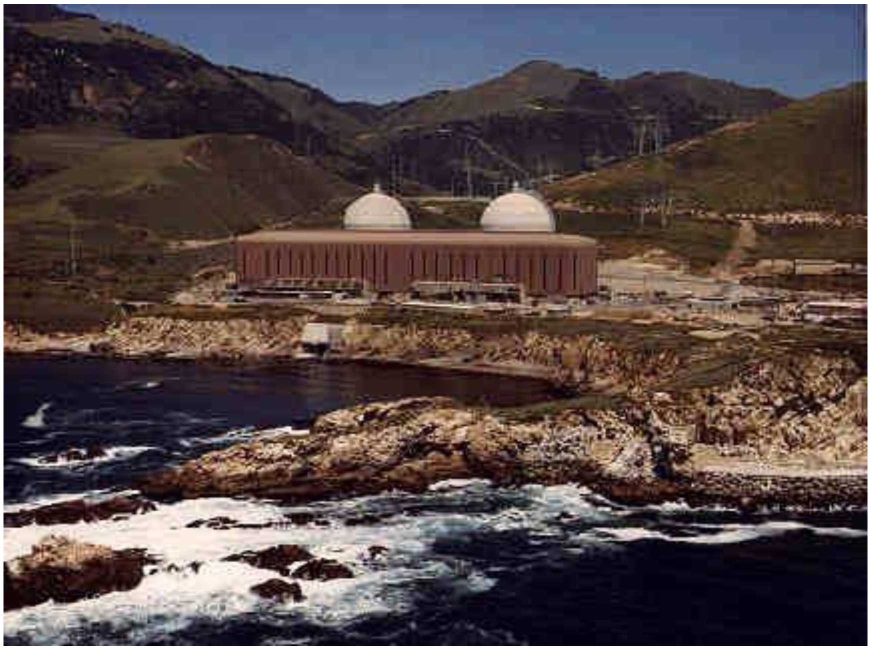


Fig. N-5: Diablo Canyon Nuclear Power Plant

Inside a BWR, heat from the chain reaction boils the water and turns it to steam. A BWR uses only one moderator[3]/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 [44]. With 57% PWR, this leaves 22%, of which most are Pressurized Heavy Water Reactors (PHWR) otherwise known as CANDU[4], a similar Russian design called Reaktor Bolshoy Moschnosti Kanalniy (RBMK), the British

[3] The moderator of a nuclear reactor is a substance that slows down the speed of the neutrons, necessary because otherwise, the rate of nuceli fission would increase too fast, releasing too much energy, causing reactor failure. Water is the moderator for PWR and BWR reactors; heavy water or graphite are used in other designs.

[4] 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.

Gas Cooled Reactor (GCR) and Advanced Gas Cooled Reactor (AGR), and a few others.

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 [45].

Table 4: Nuclear power plants in commercial operation

Reactor type	Main countries	Number	GWe	Fuel	Coolant	Moderator
Pressurized water reactor (PWR)	USA, France, Japan, Russia, China, South Korea	307	292.8	enriched UO_2	water	water
Boiling water reactor (BWR)	USA, Japan, Sweden	60	60.9	enriched UO_2	water	water
Pressurized heavy water reactor (PHWR)	Canada, India	47	24.3	natural UO_2	heavy water	heavy water
Light water graphite reactor (LWGR)	Russia	11	7.4	enriched UO_2	water	graphite
Advanced gas-cooled reactor (AGR)	UK	8	4.7	natural U (metal), enriched UO_2	CO_2	graphite
Fast neutron reactor (FNR)	Russia	2	1.4	PuO_2 and UO_2	liquid sodium	none
High temperature gas-cooled reactor (HTGR)	China	1	0.2	enriched UO_2	helium	graphite
TOTAL		436	391.7			

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)[5]. The enrichment process is illustrated in Fig. 15b [46], where the mine and the power plant are circled.

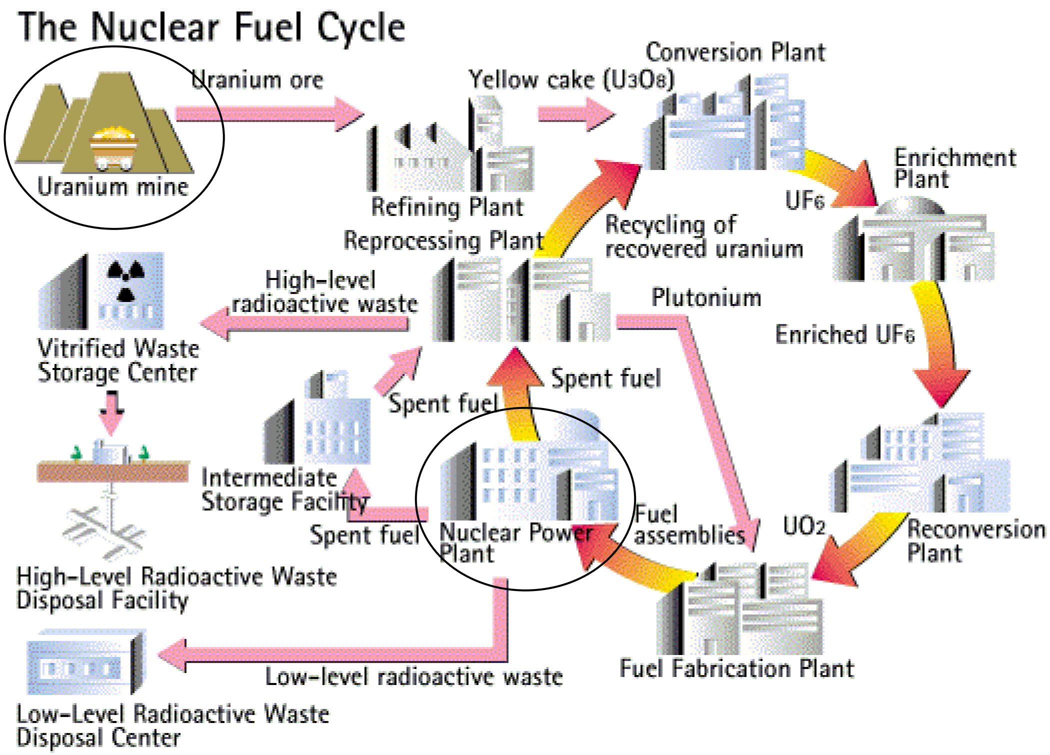


Fig. N-6: Nuclear power fuel enrichment process [46]

Steps identified in Fig. N-6 are summarized below [46]:

- Mining: Extraction of uranium ore (crude ore) from mines.
- Refining: Removal of impurities from the ore to produce yellow cake (uranium concentrate).
- Conversion: Conversion of yellow cake into uranium hexafluoride (UF_6).

[5] 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.

- Enrichment: Treatment of UF_6 to increase the concentration of uranium 235, which burns readily but which is contained only in small quantities (0.7%) in UF_6, to between 3-5 %.
- Reconversion: Conversion of enriched UF_6 to uranium dioxide (UO_2).
- Fabrication: Sintering of UO_2 to form it into hardened pellets which are sealed inside zirconium alloy tubes for arrangement into fuel assemblies.
- Generation: Loading of fuel assemblies into a reactor for use in the generation of electric power.
- Reprocessing: Recovery of the residual unburned uranium and newly produced plutonium in fuel that has been in use for 3-4 years or so (spent fuel) and separation of the radioactive waste.
- Re-use: Recovered uranium and plutonium is processed to be burned as fuel again.

Nuclear waste

Nuclear power plants 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-yr 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+ yr cool down period; this is used nuclear reactor fuel. It can exist in 2 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.

- 1982: Nuclear Waste Policy Act (NWPA) instructed DOE to investigate creation of a geologic repository for nuclear waste.
- 1987: Congress amended NWPA and directed DOE to study only Yucca Mountain, Nevada.
- 2002: President Bush signed House Resolution 87, allowing DOE to take the next step in using Yucca Mt.
- 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, see Fig. N-7 [47, 48, 49].

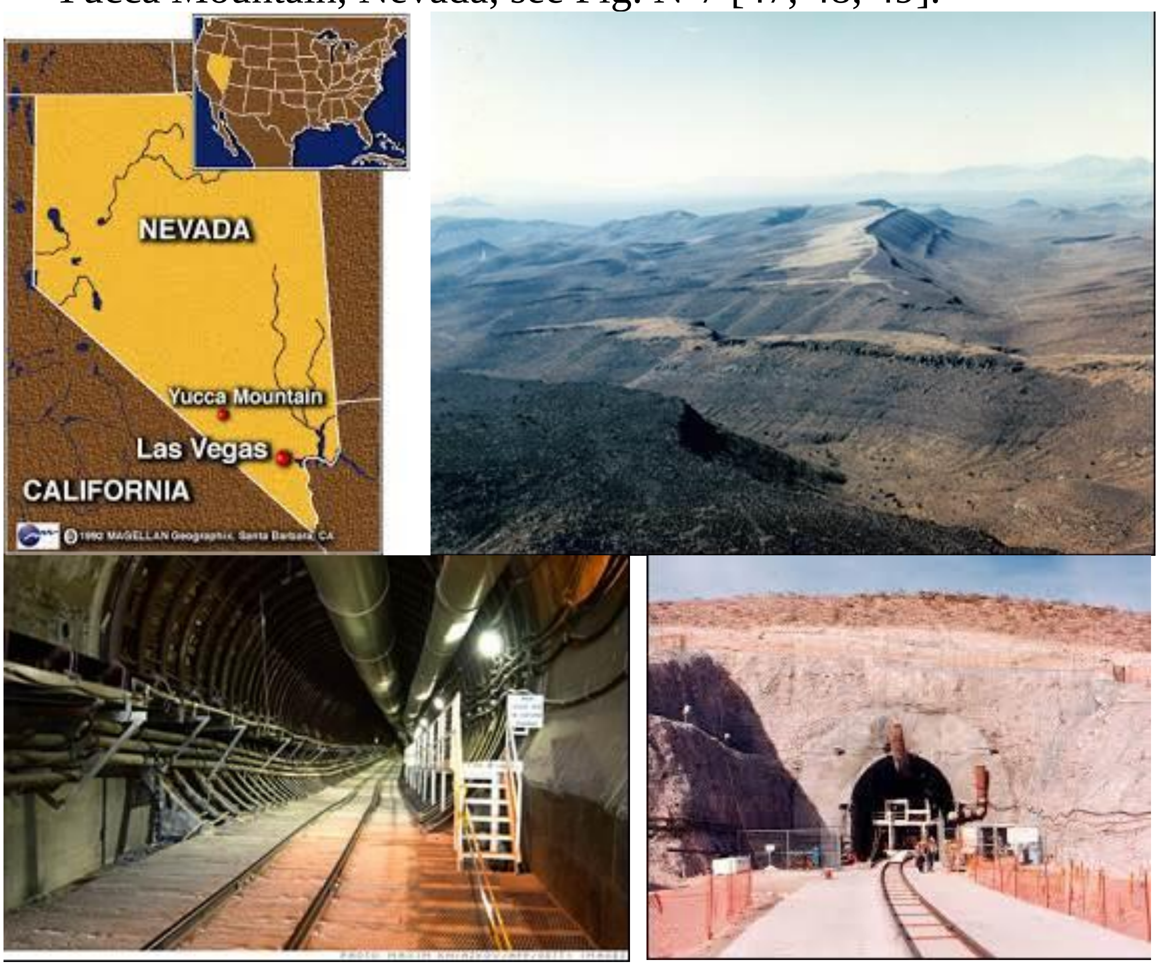


Fig. N-7: Yucca Mountain, Nevada

- Obama was inaugurated January 20, 2009.
- On January 29, 2010, DOE Secretary Steven Chu announced a 15-member “Blue Ribbon Commission” (BRC) panel of experts to “chart new paths to manage highly radioactive nuclear waste.”
- In Feb, 2010, the DOE filed a motion with the Nuclear Regulatory Commission (NRC) to "stay" the Yucca Mountain licensing review, saying that it intends to withdraw the application "with prejudice," which would prevent it from ever being considered again.
- On April 6, 2010, 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, 2010, 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.
- In June 2010, the NRC's Atomic Safety and Licensing Board (ASLB) ruled that DOE had no right to substitute its own ideas in place of those legislated by Congress. The DOE and the NRC are bound by law to complete their work at Yucca Mountain unless Congress acts to supersede the Nuclear Waste Policy Act. The ASLB stated: “Unless Congress directs otherwise, DOE may not single-handedly derail the legislated decision-making process by withdrawing

the Application. DOE's motion must therefore be denied" [50].

- October 3, 2010: NRC terminates technical review of Yucca Mountain application.
- In Jan, 2012, the BRC submitted its final report to Congress, recommending [50]
    - a "consent-based" approach whereby "communities, tribes and states, as partners, are comfortable with the location of future storage and disposal facilities before they are constructed" [51], or in other words, "instead of ordering some individual state like Nevada to take all of the Nation's high level nuclear waste, whether they like it or not, we'll instead ask 'Who would like to take this waste?' It will create fantastic jobs, will bring huge economic benefit to the region and, contrary to popular opinion, it's safer than putting in a Mall" [52].
    - Responsibility for US nuclear waste management should be transferred to a new organization, independent of DOE.
    - Treatment of the ~$31B (as of 2010) in the Nuclear Waste Fund, obtained by a levy on nuclear power production of 0.1cent/kWh, in the federal budget should be changed to ensure they are used for their intended purpose.
- August 2013: An appeals court ruled that NRC, by stopping work on Yucca Mountain, had flouted the law, thus compelling NRC to resume its examination of the Yucca Mountain's suitability for waste storage.
- On Dec. 21, 2015, DOE Secretary Ernest Moniz said, "The US Department of Energy is launching a consent-based process to site spent fuel storage and disposal facilities, as well as a separate repository for

defense high-level waste, and expects to be in the second phase of that process by the end of next year" [53].

- I am not aware that the Dr. Moniz's program ever got much attention, nor am I aware that the Trump administration moved forward with any new policies or programs in this way. A 4/2020 Congressional Research Service document [54] indicates that both House and Senate entertained bills via the Nuclear Waste Policy Amendment Act of 2019 (H.R. 2699 and S. 2917) that would have restarted the process of approving Yucca Mountain as a nuclear waste storage site [55]. The house bill was killed in the Appropriation Committee due to an attempt to add $74M in Yucca Mountain funding. Neither of these bills were approved by Congress.
- On May 20, 2020, DOE Under-Secretary Mark Menezes testified before Senate Energy and Natural Resources Committee that Trump has no plans to use Yucca Mountain as a nuclear waste storage site [56].
- In May 2021, it was reported that Nevada Senator Cortez Masto [57] "has extracted promises from Energy Secretary Jennifer Granholm that Yucca Mountain won't be part of the administration's planning for nuclear-waste disposal." Yet, the same article reported that "Ms. Granholm seems eager to still make progress on the issue, telling a House Appropriations panel last week that she anticipated announcing the department's next steps 'in the coming months.'."

- To date, the Biden Administration has not put forth a plan on nuclear waste, although they recently announced 6 new members to the Nuclear Waste Technical Review Board [58], and these folks seem to be active in their efforts to develop a plan [59]. In addition, the Biden Administration is funding research for spent fuel re-processing [60]. A promising avenue harkens back to comments from Obama/Chu/Moniz as articulated by Chu's Stanford colleagues who recommended [61] "a consent-based repository selection process and the creation of a new organization to oversee nuclear waste disposal."

The upshot of the nuclear waste issue is that on-site storage has been & will remain the solution for the foreseeable future. Fig. N-8 illustrates US on-site storage locations [54].

Sources: Compiled by CRS using various U.S. Nuclear Regulatory Commission and Nuclear Energy Institute sources, including *Evaluation of Options for Permanent Geologic Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste in Support of a Comprehensive National Nuclear Fuel Cycle Strategy*, FCRD-UFD-2013-000371, Revision 1; SAND2014-0187P (vol. I); SAND2014-0189P (vol. II), April 15, 2014; DOE, *Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites*, DOE/RW-0596, December 2008; Frank Marcinowski, *Overview of DOE's Spent Nuclear Fuel and High-Level Waste: Presentation to the Blue Ribbon Commission on America's Nuclear Future*, DOE, March 25, 2010.

Notes: *Nuclear waste* refers to spent nuclear fuel from commercial nuclear power plants and other high-level nuclear waste. The locations of research reactor sites, special nuclear materials (e.g., plutonium-239 and uranium-235), transuranic wastes, or low-level nuclear wastes were not included in this analysis. No nuclear waste storage sites are located in Alaska or Hawaii.

Fig. N-8: On-site storage locations [54]

Fig. N-9 shows all existing nuclear power plants in the US, as of 2015 [62]; Fig. N-10 shows locations of US uranium deposits [63]; Fig. N-11 shows a USGS map of uranium soil concentrations [64]; Fig. N-12 shows locations of what are thought to be uranium mines [65], and Fig. N-13 shows locations of uranium processing facilities [66].

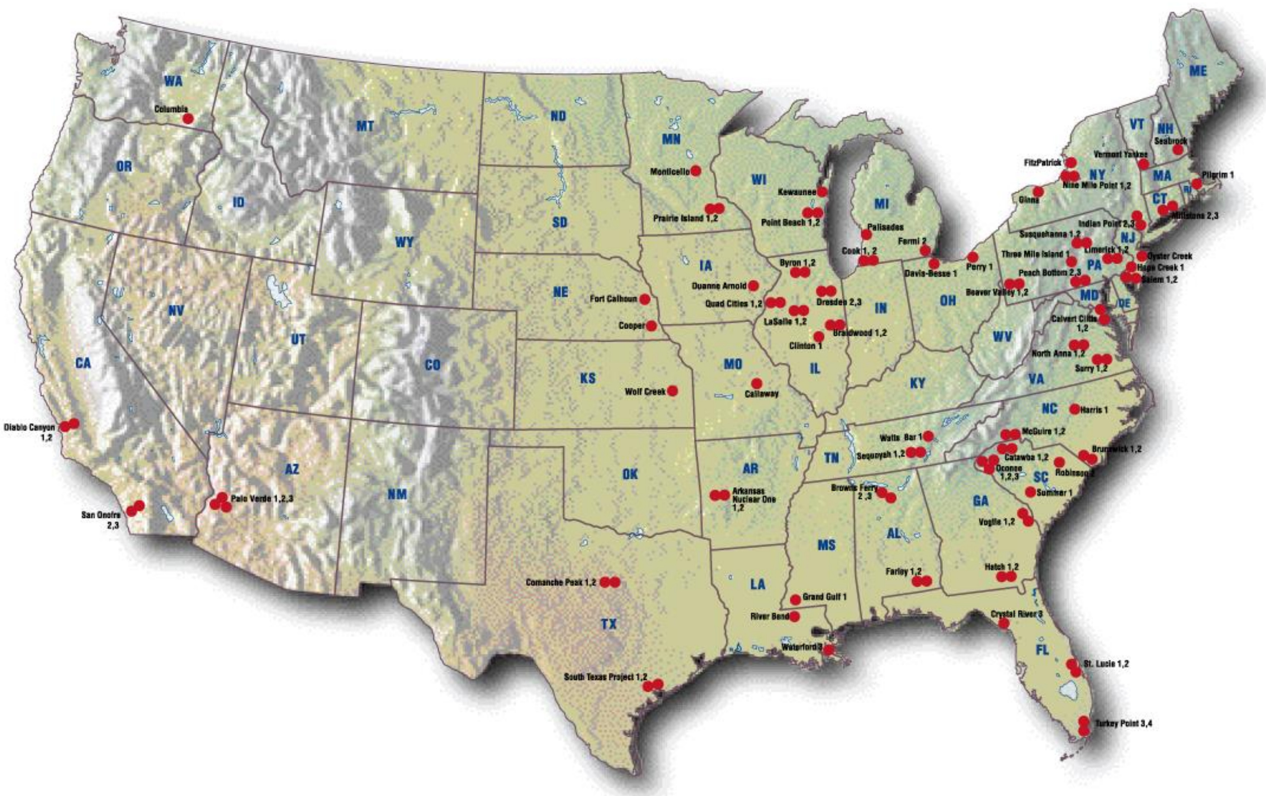


Fig. N-9: Locations of existing nuclear power plants

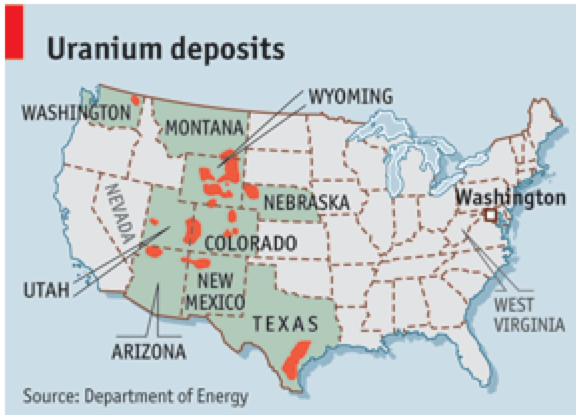


Fig. N-10: Locations of US uranium deposits

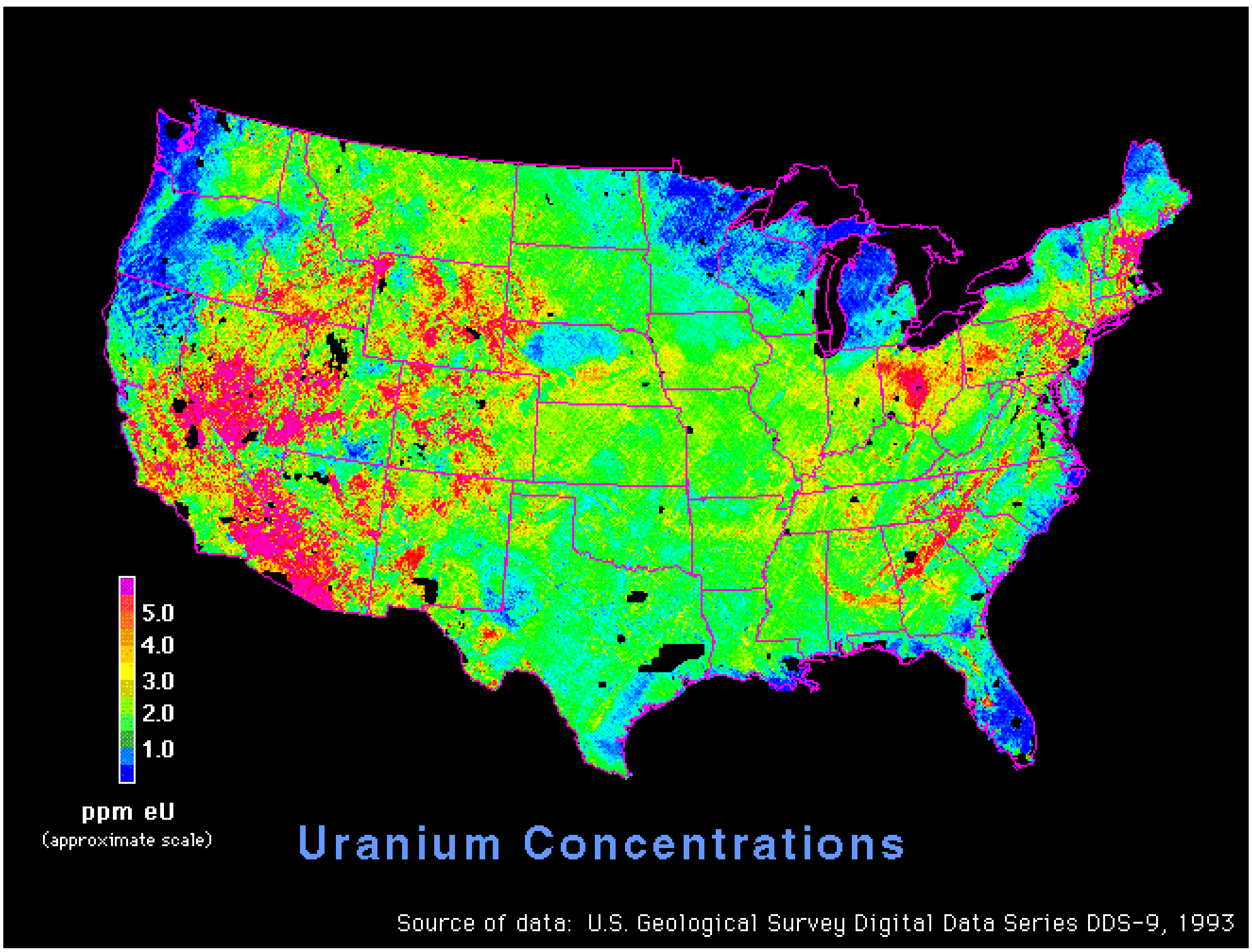


Fig. N-11: USGS map of uranium soil concentrations

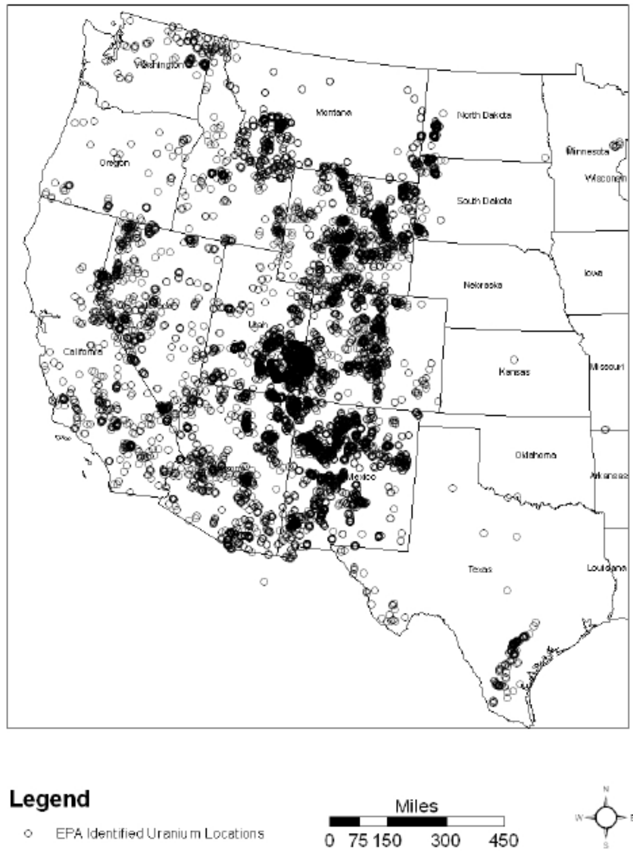


Fig. N-12: Western uranium locations from the EPA uranium location database

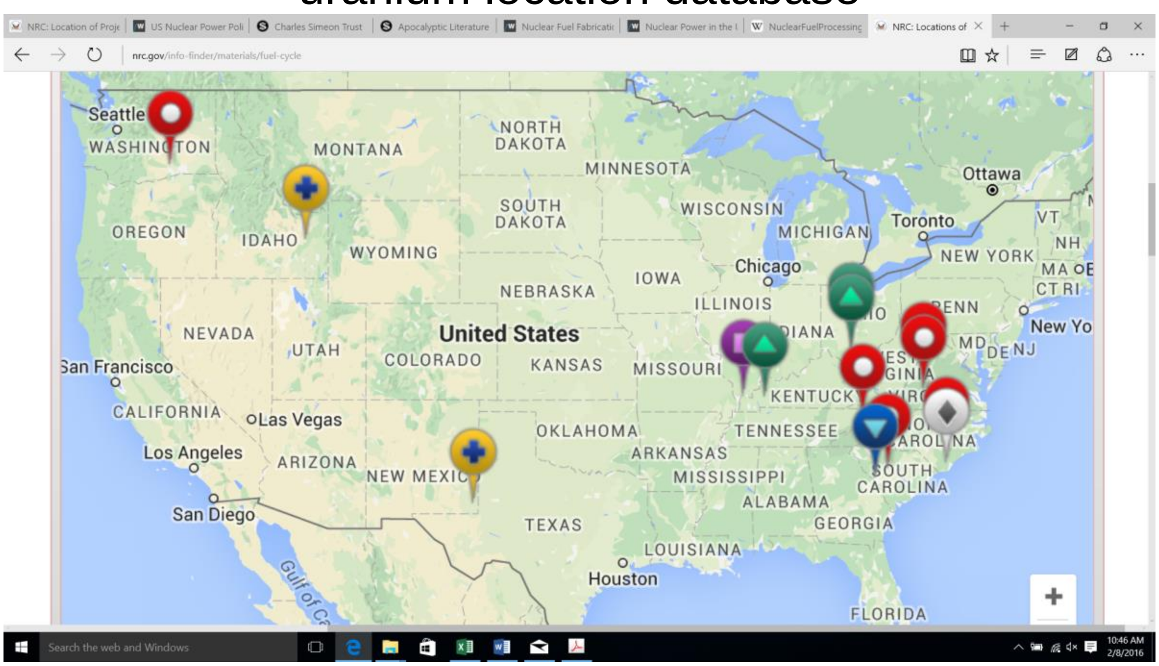


Fig. N-13: Major US nuclear fuel processing facilities

New nuclear technologies

Several generations of reactors are commonly distinguished [67].

- 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 and Gen III+ are advanced reactors, some of which are in operation in Japan, Russia. Europe, China, and India. Plant Vogtle Units 3 and 4 are Gen III+ designs. These designs are generally developments of the 2nd generation with enhanced safety. 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, one of which is operational in South Africa.

Table 5 [68] summarizes advanced (Gen III) reactors.

Table 5: Advanced Gen III reactors

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.
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-	750 925+	Enhanced model Licensing approval 1997	• Evolutionary design. • Flexible fuel requirements.

Country and developer	Reactor	Size MWe	Design Progress	Main Features (improved safety in all)
	9			• 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	1. Modular plant, low cost. 2. High fuel efficiency. 3. Direct cycle gas turbine.

• Generation IV designs were identified in by the Generation IV International Forum (GIF) in late 2002 identified six (ultimately became seven) reactor designs which were believed to represent the future of nuclear energy. In 2005, five countries agreed to undertake joint research and exchange technical information on the designs – these were US, Canada, France, Japan, and the UK. Between 2005 and 2020, additional countries joined so that there are now 12 member countries. Table 6 summarizes these designs.

Table 6: Advanced Gen IV reactors

	Neutron spectrum (fast/thermal)	Coolant	Temperature (°C)	Pressure*	Fuel	Fuel cycle	Size (MWe)	Use
Gas-cooled fast reactors	fast	helium	850	high	U-238 +	closed, on site	1200	electricity & hydrogen
Lead-cooled fast reactors	fast	lead or Pb-Bi	480-570	low	U-238 +	closed, regional	20-180** 300-1200 600-1000	electricity & hydrogen
Molten salt fast reactors	fast	fluoride salts	700-800	low	UF in salt	closed	1000	electricity & hydrogen
Molten salt reactor - **advanced high-temperature reactors**	thermal	fluoride salts	750-1000		UO_2 particles in prism	open	1000-1500	hydrogen
Sodium-cooled fast reactors	fast	sodium	500-550	low	U-238 & MOX	closed	50-150 600-1500	electricity
Supercritical water-cooled reactors	thermal or fast	water	510-625	very high	UO_2	open (thermal) closed (fast)	300-700 1000-1500	electricity
Very high temperature gas reactors	thermal	helium	900-1000	high	UO_2 prism or pebbles	open	250-300	hydrogen & electricity

* high = 7-15 MPa
\+ = with some U-235 or Pu-239
** 'battery' model with long cassette core life (15-20 yr) or replaceable reactor module.

But there have been and are impediments.
The US was extremely nuclear-positive in the 2000-2010 period (see appendix). However, expectations have not been met, and the expected level of nuclear growth never occurred, for multiple reasons:
(1) growth of inexpensive wind and solar technologies;
(2) continued safety concerns (e.g., the 2011 Fukushima tsunami-nuclear accident in Japan);

(3) the long lead times for constructing nuclear plants;
(4) the difficulty of addressing radioactive waste;
(5) the high cost;
(6) perceived financial risk of lending institutions; and
(7) human resources for new nuclear engineers and technicians are not great right now.

The below Table 7b indicates the state of combined license applications [69] as of 8/28/2020. Eight have been issued (in yellow), 1 is under review, and the other 10 have either been suspended or withdrawn. Of the 8 with issued licenses, only Vogtle Units 3,4 are under construction. I am not aware of whether any of the other 7 are likely to move forward or not. Table 7c indicates the same as of 2/8/2024. A detailed assessment of the status of each is given at www.world-nuclear.org/information-library/country-profiles/countries-t-z/usa-nuclear-power.aspx.

Table 7b: Status of COL applications, 2020

Proposed New Reactor(s)	Design	Applicant	Status
Aurora		Oklo, Power LLC	Under Review
Bell Bend Nuclear Power Plant	U.S. EPR	PPL Bell Bend, LLC	Withdrawn
Bellefonte Nuclear Station, Units 3 and 4	AP1000	Tennessee Valley Authority (TVA)	Withdrawn
Callaway Plant, Unit 2	U.S. EPR	AmerenUE	Withdrawn
Calvert Cliffs, Unit 3	U.S. EPR	Calvert Cliffs 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC	Withdrawn
Comanche Peak, Units 3 and 4	US-APWR	Luminant Generation Company, LLC (Luminant)	Suspended

Fermi, Unit 3	ESBWR	Detroit Edison Company	Issued
Grand Gulf, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)	Withdrawn
Levy County, Units 1 and 2	AP1000	Duke Energy Florida (DEF)	Issued
Nine Mile Point, Unit 3	U.S. EPR	Nine Mile Point 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC (UniStar)	Withdrawn
North Anna, Unit 3	ESBWR	Dominion Virginia Power (Dominion)	Issued
River Bend Station, Unit 3	ESBWR	Entergy Operations, Inc. (EOI)	Withdrawn
Shearon Harris, Units 2 and 3	AP1000	Progress Energy Carolinas, Inc. (PEC)	Suspended
South Texas Project, Units 3 and 4	ABWR	Nuclear Innovation North America, LLC (NINA)	Issued
Turkey Point, Units 6 and 7	AP1000	Florida Power and Light Company (FPL)	Issued
Victoria County Station, Units 1 and 2	ESBWR	Exelon Nuclear Texas Holdings, LLC (Exelon)	Withdrawn
Virgil C. Summer, Units 2 and 3	AP1000	South Carolina Electric & Gas (SCE&G)	Issued
Vogtle, Units 3 and 4	AP1000	Southern Nuclear Operating Company (SNC)	Issued
William States Lee III, Units 1 and 2	AP1000	Duke Energy	Issued

Table 7c: Status of COL applications, 2024

Proposed New Reactor(s)	Design	Design Type	Applicant	Status	Application Submittal Date
Aurora - Oklo Application	Aurora	Non-Light Water Reactor (LWR)	Oklo Power, LLC	Denied	03/11/2020
Turkey Point, Units 6 and 7	AP1000	Large LWR	Florida Power & Light Company (FPL)	Issued*	06/30/2009
Fermi, Unit 3	ESBWR	Large LWR	Detroit Edison Company	Issued*	09/18/2008
Levy Nuclear Plant, Units 1 and 2	AP1000	Large LWR	Duke Energy Florida, LLC (DEF)	Issued*	07/30/2008
Vogtle, Units 3 and 4	AP1000	Large LWR	Southern Nuclear Operating Company (SNC)	Issued*	03/28/2008
Virgil C. Summer, Units 2 and 3	AP1000	Large LWR	South Carolina Electric & Gas (SCE&G)	Issued*	03/27/2008
William States Lee III, Units 1 and 2	AP1000	Large LWR	Duke Energy	Issued*	12/13/2007
North Anna, Unit 3	ESBWR	Large LWR	Dominion Virginia Power (Dominion)	Issued*	11/27/2007
South Texas Project, Units 3 and 4	ABWR	Large LWR	Nuclear Innovation North America, LLC (NINA)	Issued*	09/20/2007
Comanche Peak, Units 3 and 4	US-APWR	Large LWR	Luminant Generation Company, LLC (Luminant)	Suspended	09/19/2008
Shearon Harris, Units 2 and 3	AP1000	Large LWR	Progress Energy Carolinas, Inc. (PEC)	Suspended	02/18/2008
Bell Bend Nuclear Power Plant	U.S. EPR	Large LWR	PPL Bell Bend, LLC	Withdrawn	10/10/2008
Nine Mile Point, Unit 3	U.S. EPR	Large LWR	Nine Mile Point 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC (UniStar)	Withdrawn	09/30/2008
River Bend Station, Unit 3	ESBWR	Large LWR	Entergy Operations, Inc. (EOI)	Withdrawn	09/25/2008
Victoria County Station, Units 1 and 2	ESBWR	Large LWR	Exelon Nuclear Texas Holdings, LLC (Exelon)	Withdrawn	09/03/2008
Callaway Plant, Unit 2	U.S. EPR	Large LWR	AmerenUE	Withdrawn	07/24/2008
Grand Gulf, Unit 3	ESBWR	Large LWR	Entergy Operations, Inc. (EOI)	Withdrawn	02/27/2008
Bellefonte Nuclear Station, Units 3 and 4	AP1000	Large LWR	Tennessee Valley Authority (TVA)	Withdrawn	10/30/2007
Calvert Cliffs, Unit 3	U.S. EPR	Large LWR	Calvert Cliffs 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC	Withdrawn	07/13/2007

Small modular reactors

A final section here is that there is very high interest today, world-wide, in what are called Small Modular Reactors (SMRs). SMRs may be either Gen III or Gen IV designs but their key features, obviously, are that they are (i) small and (ii) modular. In this sense, they are borrowing design features from nuclear submarines. These two features are thought to provide benefits in terms of safety, lead times, cost, and financial risk.

The US DOE has been funding development of this technology now for over two decades, and today, there are a number of US companies trying to mature these designs. Some of these companies include:

- NuScale Power
- TerraPower (founded in 2008 by Bill Gates)
- Westinghouse
- BWXT Technologies (a subsidieary of BWX Technologies)
- Kairos Power

As of 2023, only China and Russia have successfully built operational SMRs. The US DOE had expected NuScale Power (see Fig. N-14 below) to complete the first US SMR demonstration plant in Idaho by 2029 but this project was recently canceled on account of rising costs [70].

Fig. N-14: A possible layout for an SMR power plant

9.0 Hydroelectric plants

There are 3 types of hydroelectric plants: reservoir (also called impoundment), run-of-river (also called diversion), and pumped storage hydro (PSH).

Reservoir hydro plants

Reservoir facilities use a dam to store river in a reservoir, which, when released, flows through a penstock to turn a turbine which rotates a generator. Figure H-1 [71] illustrates.

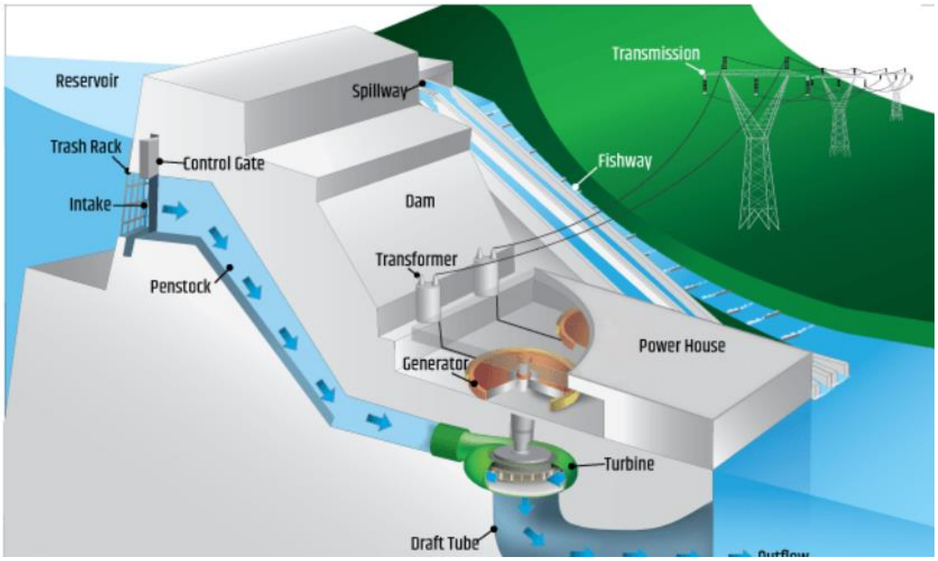


Figure H-1: An reservoir hydroelectric facility [71]

Reservoir systems are typically created where large water systems occur in highly mountainous terrain so that one or a series of cascading lakes, either natural or enlarged with dams, form reservoirs. Each lake has an associated penstock that runs down the mountainside and leads to one or more turbines. Fig. H-2 [72] shows the 10 largest hydroelectric facilities in the US, of which most are reservoir systems. The major US reservoir systems are in the states of Washington, Nevada, California, and Tennessee. The Colombia River system which flows from British Columbia to Washington State to Oregon has 14 reservoir dams ranging from 185 MW to 6809 MW (Grand Coulee Dam) for a total capacity of 24,149 MW (the overall watershed which also includes the Snake River includes more than this).

Facility Name	State	Waterway	Generation (MW)	Owner
Grand Coulee	*WA*	*Columbia*	*6,800 MW*	*USBR*
Chief Joseph	*WA*	*Columbia*	*2,457*	*USACE*
John Day	*WA-OR*	*Columbia*	*2,160*	*USACE*
Hoover	*AZ-NV*	*Colorado*	*2,100*	*USBR*
Bath County PS*	VA	Little Back	2,100	Dominion Power**
Robert Moses	NY	Niagara	1,950	NY Power Authority
The Dalles	*WA-OR*	*Columbia*	*1,807*	*USACE*
Ludington PS*	MI	Lake Michigan	1,872	Consumers/Detroit**
*Raccoon Mtn. PS**	*TN*	*Tennessee*	*1,618*	*TVA*
Glen Canyon	*AZ*	*Colorado*	*1,288*	*USBR*

* PS means "pumped storage." In a pumped storage plant, water is pumped uphill during times of low demand to a reservoir from where the water flows by gravity through turbine-generators during times of peak demand.

** Indicates private power utility. Dominion Power is based in Virginia. Consumers Energy and Detroit Edison in Michigan jointly own the Ludington plant.

Fig. H-2: Ten largest hydroelectric facilities in the US

Run-of-river hydro plants

A run-of-river facility, on the other hand, may send river water through a penstock, utilizing the natural flow of the river to produce energy. Fig. H-3 illustrates [71]. Alternatively, a dam may be placed across a river to create a height differential between the upstream inlet and the downstream outlet, but without creating an expansive reservoir on the upstream side [73]. Figure H-4 [74] illustrates a number of run-of-river projects.

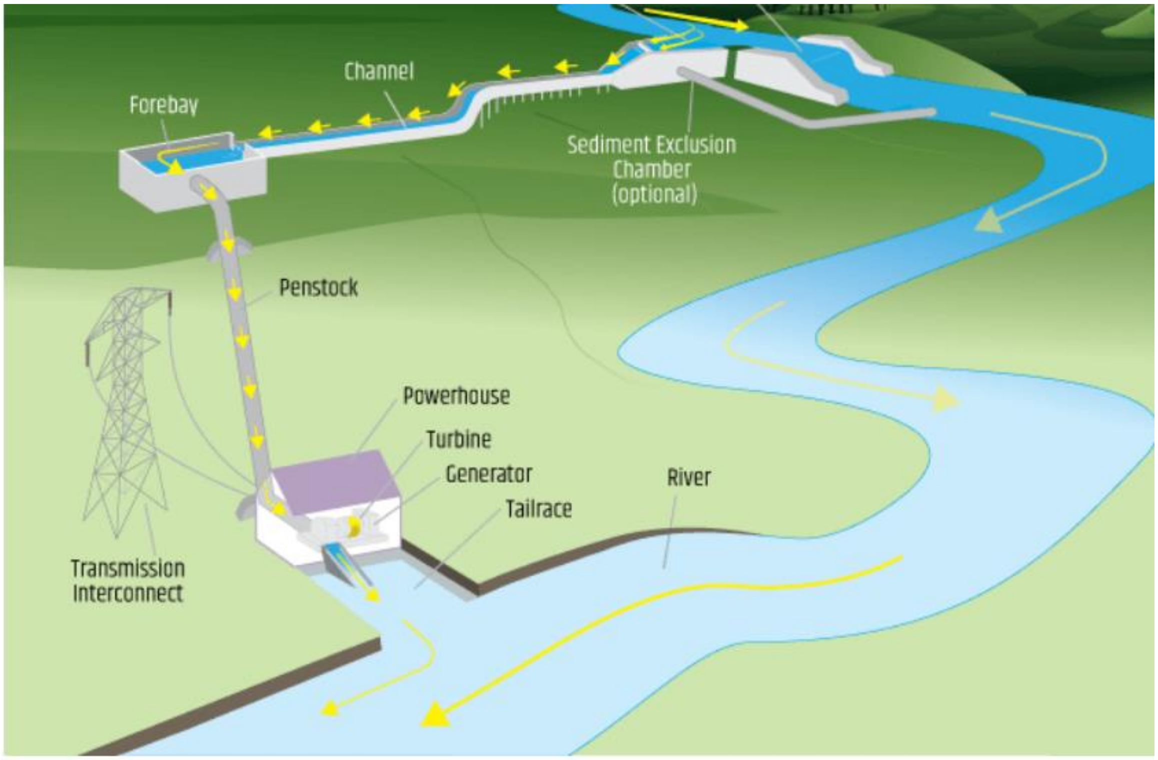


Figure H-3: An run-of-river hydroelectric facility [71]

Fig. H-4 [74]

Pumped storage hydro (PSH) plants

This kind of hydro plant is a specialized reservoir-type plant which has capability to act as both a source and a sink of electric energy. In the source or generation mode, it supplies power to the grid using the kinetic energy of the water as it falls from higher-lake to lower-lake as would a typical reservoir plant. In the sink or pumping mode, it consumes power from the grid in order to pump water from the lower lake to the higher lake. Thus, electric energy from the grid is converted into potential energy of the water at the higher elevation.

The original motivation for pumped storage plants was to valley-fill and peak-shave.

- Valleys: During low-load periods, the plant is used in pumping mode, thus increasing overall system load. This is beneficial because a decreased number of thermal plants will need to be shut-down (avoiding shut-down and start-up costs), and for those remaining on-line, they can be used at higher, more efficient generation levels.
- Peaks: During high-load periods, the plant is used in generating mode, thus decreasing the overall system load that must be met by thermal generation. This is beneficial because it avoids the need to start some of the expensive peaking plants.

Figure H-5 [75] illustrates a typical 24 cycle for a northwestern region of the US.

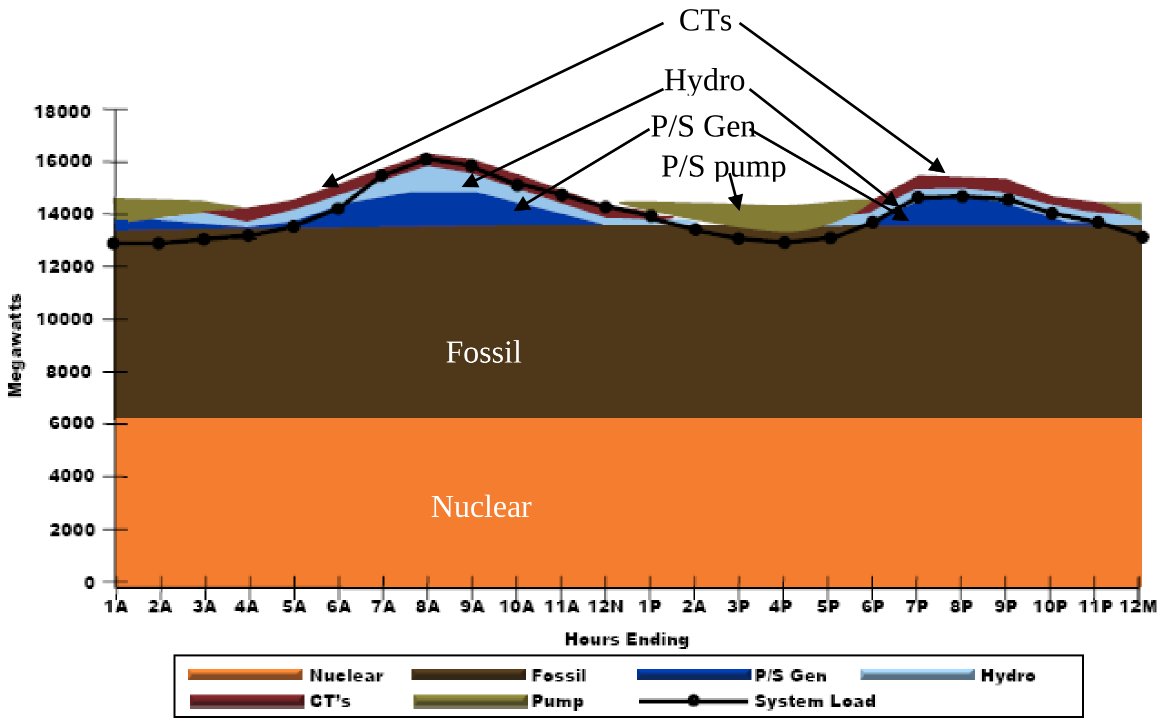
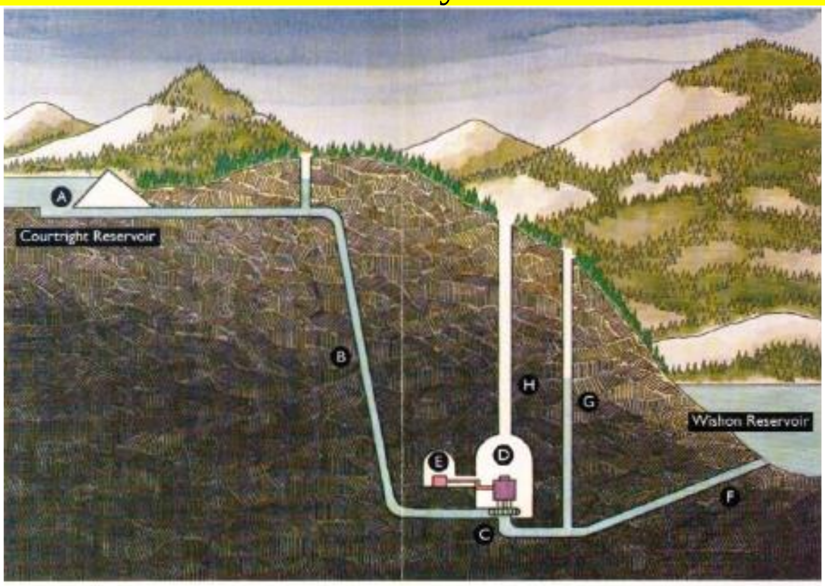


Fig. H-5 [75]

Of course, the cycle of pumping and generating incurs a net loss. It is typical for the efficiency of a round-trip pump storage cycle to be about 70%; for every 100 MW used to pump water, only about 70 MW will be recovered by the grid. The cost of this loss is lessened by the fact that the energy is supplied by thermal plants operating at higher (and thus more efficient) loading levels because of the presence of the pumping. This cost is compensated by the savings incurred by avoiding shut-down and start up costs of the thermal plants during the valleys and by avoiding the start-up costs of the peaking plants during the peaks.

Pump storage has become of even greater interest today because it offers a way to store energy that is available from renewable resources (wind and solar) during off-peak times so that they can then be used during on-peak times. Figure 3 [75] illustrates a situation in the BPA region (which is seeing significant wind growth) where the wind plants are frequently generating when load is low and not generating when load is high. Pump storage also supplies regulation and load following to which renewables generally do not contribute.

One pump-storage plant is called Helms pumped storage plant, commissioned in 1984. It consists of three units rated at 404 MW (1212 MW total) in the generating mode and 310 MW (930 MW total) in the pumping mode. Figure H-6 [76] illustrates the overall setup of Helms which operates between Courtright and Wishon Lakes about 50 miles east of the city of Fresno California.



A-Courtright, B-Supply Tunnel, C-Turbine, D-Generator, E-Transformer, F-Wishon, G-Surge Chamber, H-Elevator

Fig. H-6 [76]

Figure H-7 [76] shows the powerhouse for Helms, where one can observe that it is underground (at a depth of 1000 ft!).

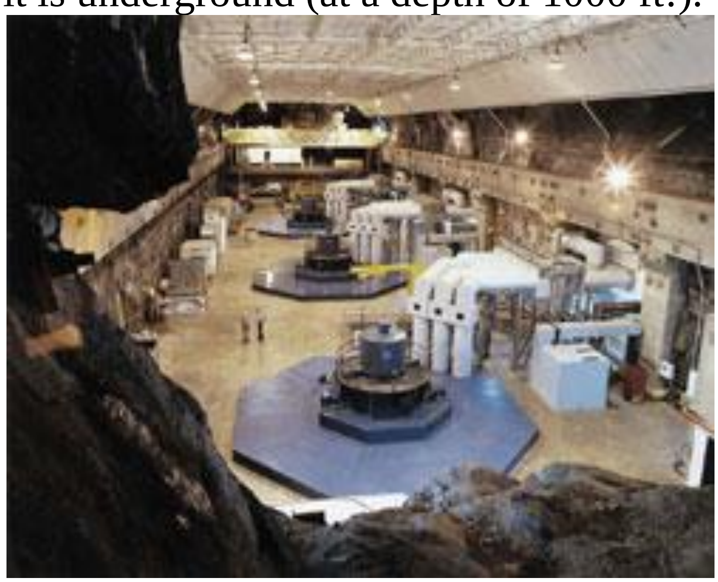


Fig. H-7 [76]

In addition to the ability to peak shave and valley fill, Helms and most pumped storage plants are highly flexible. with operating flexibility characterized by the following attributes:

- Dead stop to full generation in 8 minutes.
- Dead stop to full pumping in 20 minutes.
- Ramp rate of 80 MW/min per unit (about 20% per minute!)

This level of operational flexibility is highly desirable for systems that have high wind and solar penetration levels. An excerpt from [78] is of interest here:

> "The United States has significant resource potential for new PSH development. New advanced PSH technology with improved capabilities such as adjustable speed, closed loop, and modular designs can further facilitate integration of variable generation, such as wind and solar, due to its ability to provide grid flexibility, reserve capacity, and system inertia."

Reference [77] indicates that the US currently has 43 PSH plants totaling 21.6 GW and has potential to more than double its current PHS capacity. This potential is indicated in Fig. H-8.

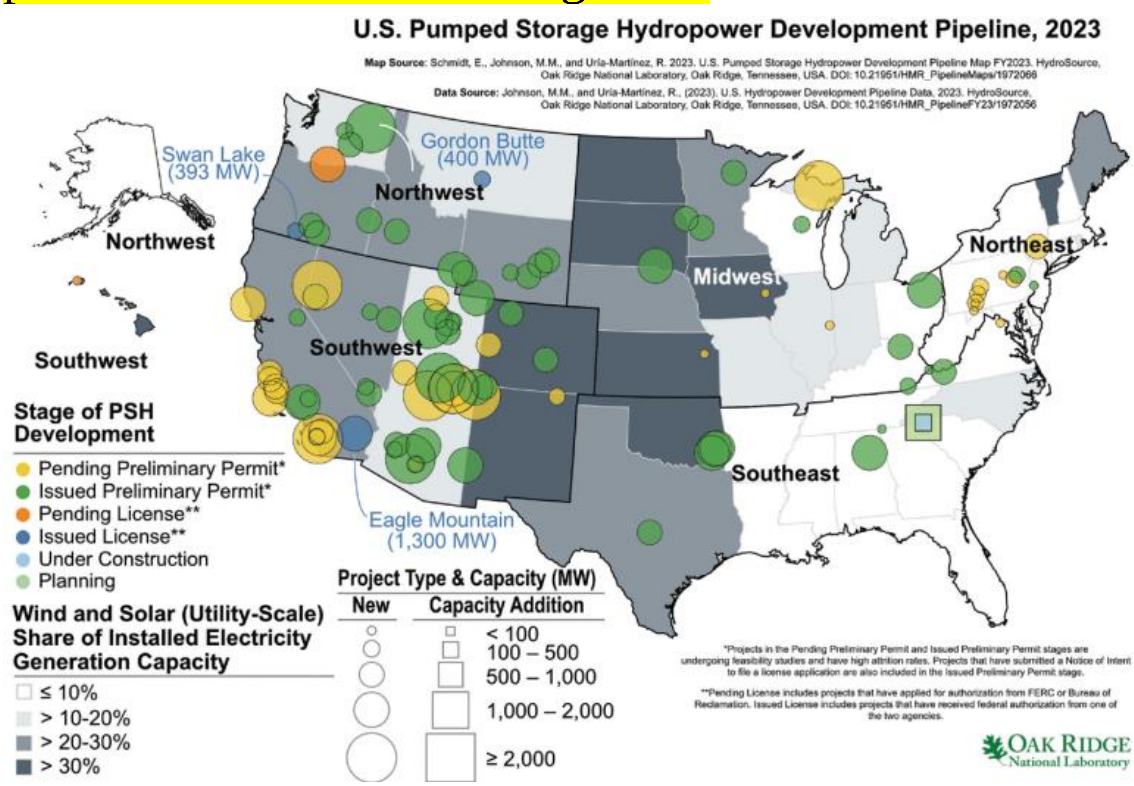


Fig. H-8: Pumped Hydro Potential in the US [77]

Hydro summary

By the end of 2015, the U.S. hydropower generation fleet included 2,198 active power plants with a total capacity of 79.6 GW and 42 PSH plants totaling 21.6 GW, for a total installed hydropower capacity of 101 GW (total US generation capacity today is about 1150 GW, and so about 8.8% is hydro; hydro produces almost 7% of total electric energy in the US).

Figure H-8 illustrates hydropower capacity related to reservoir and run-of-river facilities in the US today [78]. Figure H-9 illustrates pumped storage facilities.

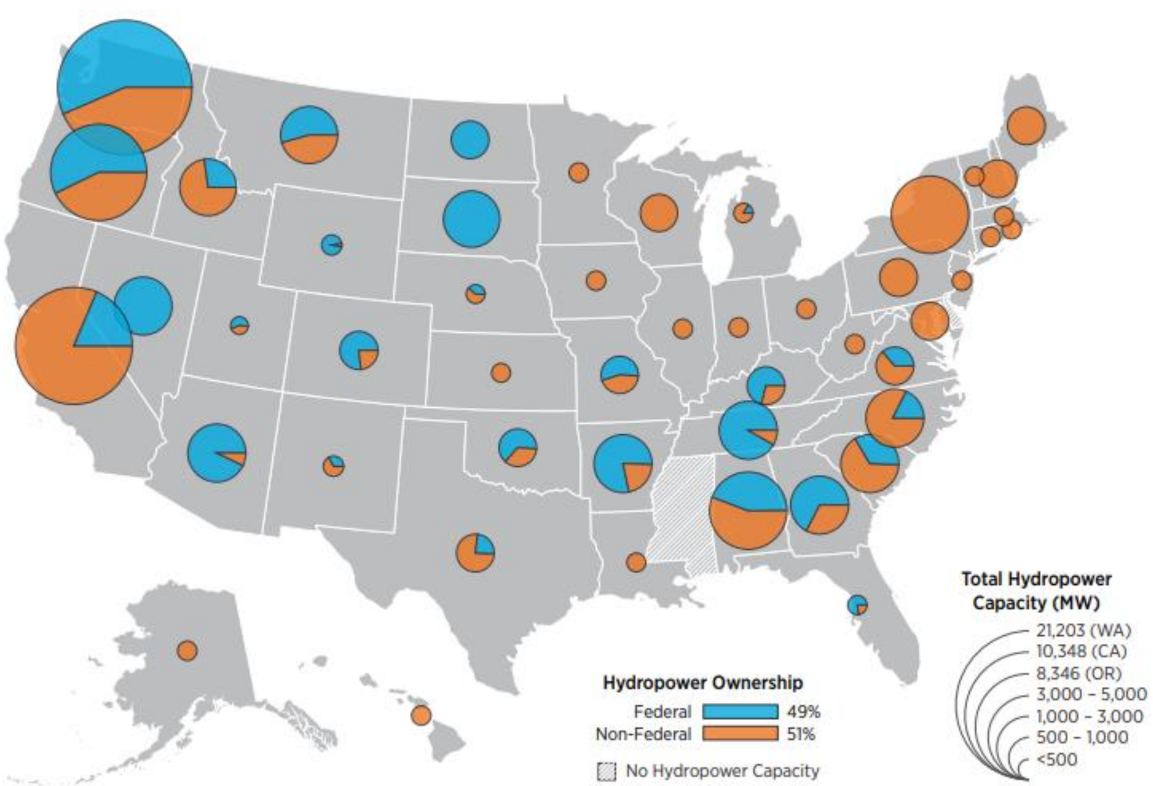


Fig. H-8: US reservoir & run-of-river hydro facilities [78]

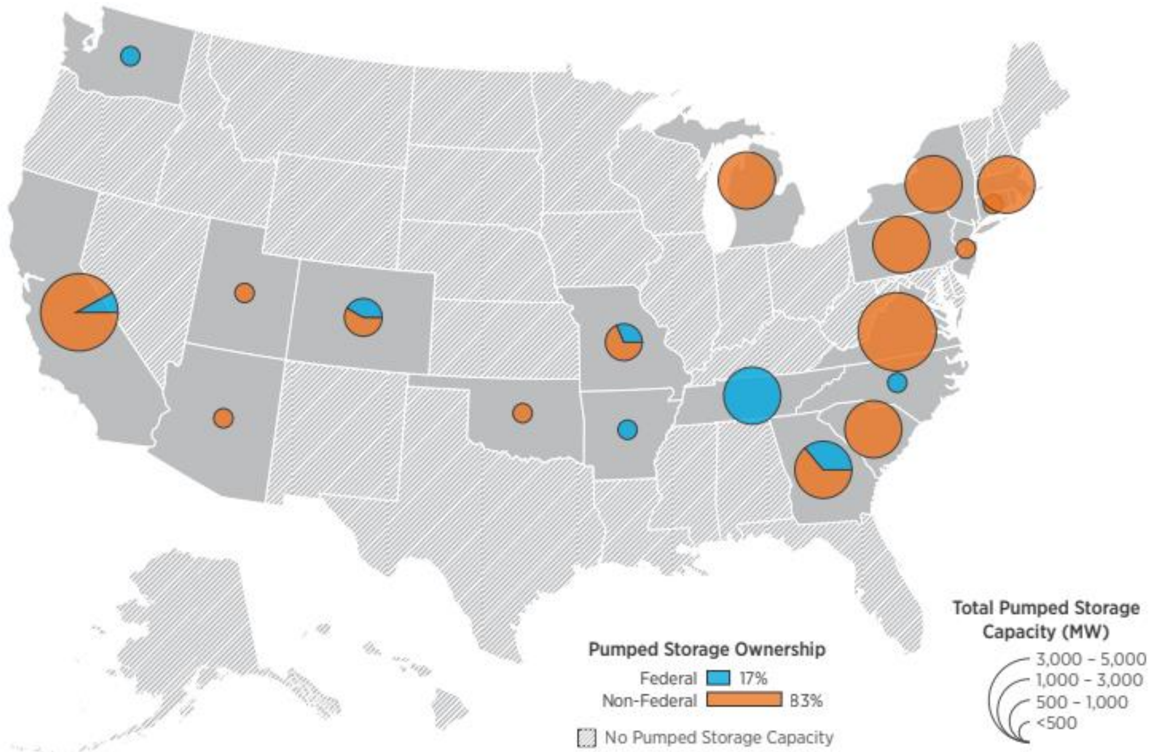


Fig. H-9: US pumped storage hydro facilities [78]

Hydro is very attractive for providing flexibility needed to increase wind and solar resources. And so there is significant interest in finding ways to increase hydro. The recent DOE-sponsored "Hydrovision" study [78] made this case very strongly, in two ways. First, it provided the evidence that that hydro has been and will continue to be an excellent provider of grid services, something that high wind and solar penetration levels require. An excerpt from [78] to this effect is provided in Fig. H-10 below.

Grid Ancillary Services Relevant to Hydropower

Regulation and frequency response: *The ability of a resource or a system to respond to changes in system frequency, which must be maintained close to a constant level (60 Hertz).* NERC establishes control performance standards to ensure that each control area maintains reliability. This response can be provided by generators through three mechanisms:

- Inertia: A passive response, typically due to rotating masses in generators
- Primary frequency response or governor control: An active, unmanned response implemented through an electronic, digital, or mechanical device
- Frequency regulation: An active response to adjust an area's generation from a central location in order to maintain the area's interchange schedule and frequency

Hydropower generators can provide these regulation services. While hydropower turbines are able to respond to sudden changes in system frequency, the relatively large mass rotating in hydropower turbine generators and the dynamics of the water column in the penstock mean hydropower may have a lower response time than do gas or steam [75]. This larger inertia can, however, be an advantage in smaller or islanded power systems as it contributes to system stability [76].

Load-following and flexibility reserve: *The ability of the power system to balance variability existing in the load over longer timeframes than regulation and frequency response, from multiple minutes to several hours.* This function is typically accomplished by mid-merit (intermediate) and peaker units. Most U.S. hydropower units are able to and do effectively provide load following to an hourly schedule, as well as following ramps that occur within the hour time scale. This flexibility is not without impact, however. Increased variation in hydropower generation can impact riverbank erosion and aquatic life, as well as increase operating costs and decrease system lifetime. In order to determine optimal use of hydropower for load-following services, these impacts must be considered against the cost of providing load following from other types of generation.

Energy imbalance service: *The transmission operator provides energy to cover any mismatch in hourly energy between the transmission customer's energy supply and the demand that is served in the balancing authority area.*

Spinning reserve: *Online (connected to the grid) generation that is reserved to quickly respond to system events (such as the loss of a generator) by increasing or decreasing output.* Except when already running at full load, hydropower offers an excellent source of reserve because it has high ramping capability throughout its range.

Supplemental (non-spinning) reserve: *Offline generation that is capable of being connected within a specified period (usually 10 minutes) in response to an event in the system.* Offline hydropower generation is capable of synchronizing quickly, and can provide non-spinning reserve to the extent that sufficient water supply is available to the unit for generation.

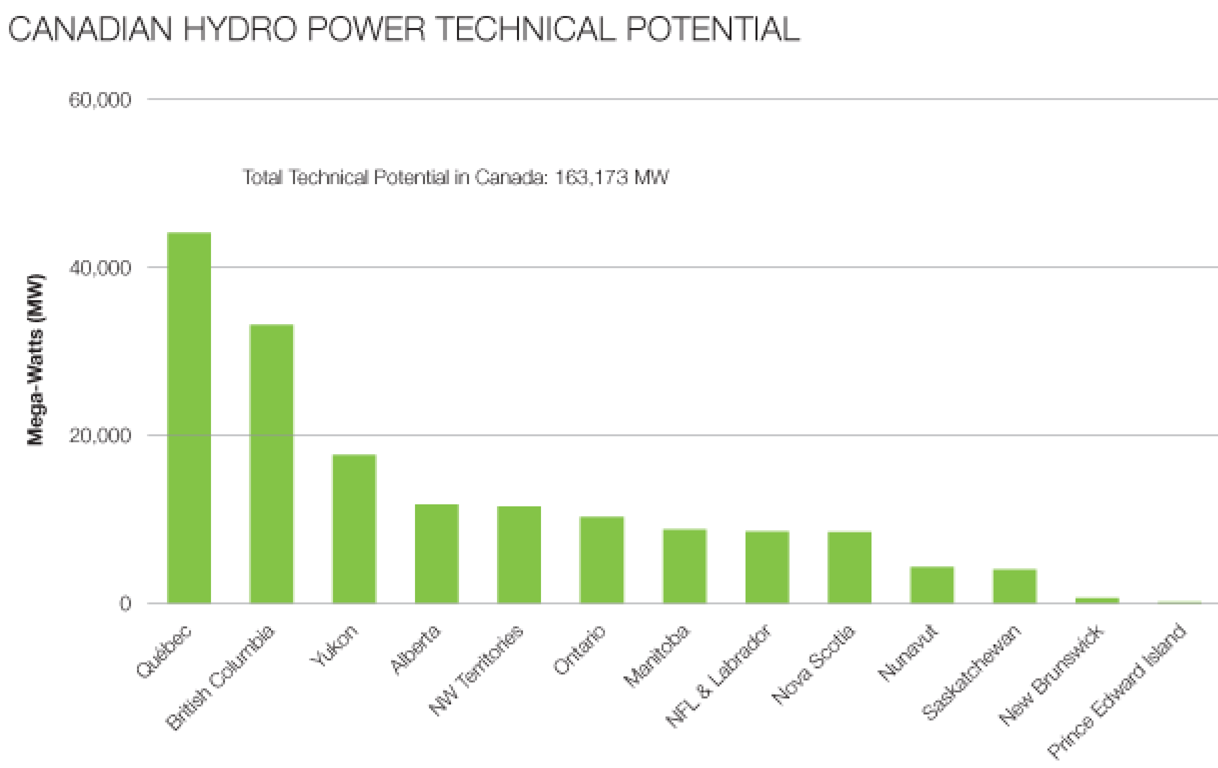
Reactive power and voltage support: *The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment.* Insufficient provision of reactive power can lead to voltage collapses and system instability. All hydropower facilities are operated to follow a voltage schedule to ensure sufficient voltage support. Reactive power is typically a local issue. Because hydropower facilities are often located in remote areas, their ability to provide reactive power in such locations can be essential.

Black start (restoration) service: *The capability to start up in the absence of support from the transmission grid.* This capability is of value to restart sections of the grid after a blackout and can typically be provided by hydropower.

Fig. H-10: Summary of grid services from hydro [78]

Second, reference [78] identified three basic thrusts, all of which will contribute, not only to the provision of those all-important grid services but also to the provision of zero-carbon electric energy. These thrusts are:

- Build medium-size facilities (0.5-10 MW) in US.
- Build small-size facilities (10-100 MW) in US.
- Build Canadian hydro with the necessary transmission. The Canadian potential is illustrated below [79], amounting to about 167 GW of hydro capacity.



10.0 Wind energy

One of the first wind farms in the US was built at Altamont Pass, southeast of Oakland, California along the I-580 freeway. The technology was induction generators on lattice steel towers [80]. The first deployment, in 1981, was comprised of 828 Kenetech turbines, each of 100 kW capacity for an 80MW wind farm. Because induction generators were used, it was a continuous sink for reactive power. In addition, because of its location, it had undesirable effects on endangered birds, raptors, particularly golden eagles [81]. Additional, newer turbines were added over the years; most of the original turbines were dismantled in 2016 and the site repowered. Today, over 6,200 wind turbines with total capacity of 583 MW are sited there [81]. An aerial view of a portion of Altamont Pass is shown in Figure W-1 [80].

Fig. W-1: Altamont Pass, California [80]

Wind Growth and Subsidies

As of 2023 Q3, the US had 146,720 MW (147 GW) of wind capacity, as shown in Fig. W-2 [82]. At 10% (2022), wind energy produces the second most zero-carbon energy in the US today (1rst is nuclear at 19%; 3rd is hydro at 6%, 4th is solar PV at 3.4%).

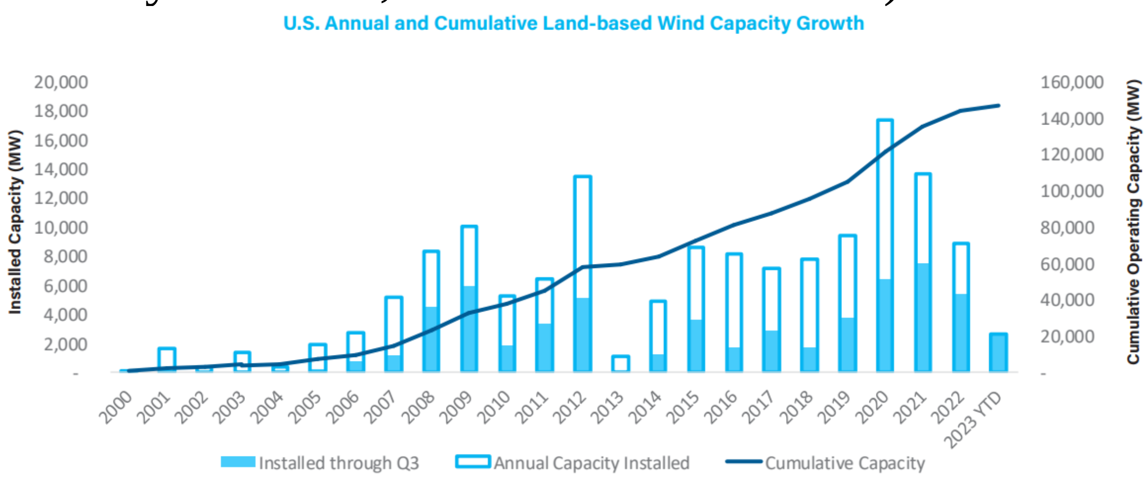


Fig. W-2: Growth of US Wind Capacity since 2000

The US production tax credit (PTC) for wind energy was established at the federal level in 1992 [83]; it provided a tax credit to a facility for 10 years of \$15/MWh, gradually increasing (per inflation adjustments) until it is now (2023) \$27.50/MWh.

Consideration of wind growth in 1997-1999 (just previous to the first year of the Fig. W-2 chart) shows that all three of those years saw greater wind capacity growth than did the year 2000. Likewise, we observe significant drop in wind growth in 2002, 2004, and in 2013. There is also a drop in 2023. All four of these years saw expiration of the production tax credit (PTC), which meant that wind plants commisioned during those years would not be see PTC benefits.[6]

Wind growth has heavily depended on the PTC. As previously indicated, the PTC provides a direct tax rebate from the federal government of about $27/MWh ($27/MWh) of wind energy production over the first 10 years of the plant's life. Is this very much?

Consider that energy prices (market LMPs, as shown for the MISO region here https://api.misoenergy.org/MISORTWD/lmpcontourmap.html) are not often above ~$80/MWh (and sometimes they are negative when when it is economic for fossil units, having minimum gen levels and long shut-down and start-up times, to pay money to remain committed rather than shut down and then start up), and usually they are between $10 and $50/MWh. So $22/MWh is ***a lot***! When LMPs are $20-$25/MWh, as they were at 8:45pmCT on 2/10/2024 (see Fig. W-3), the PTC doubles the revenues! The PTC can even motivate wind farms to generate when the LMPs are negative.

[6] There is also some drop in 2010-2011. This was because of the poor 2008-2009 economy (inhibiting developers commitment for starting new projects and influencing financiers to be less willing to provide loans for building large projects like wind farms) and declining natural gas prices due to fracking.

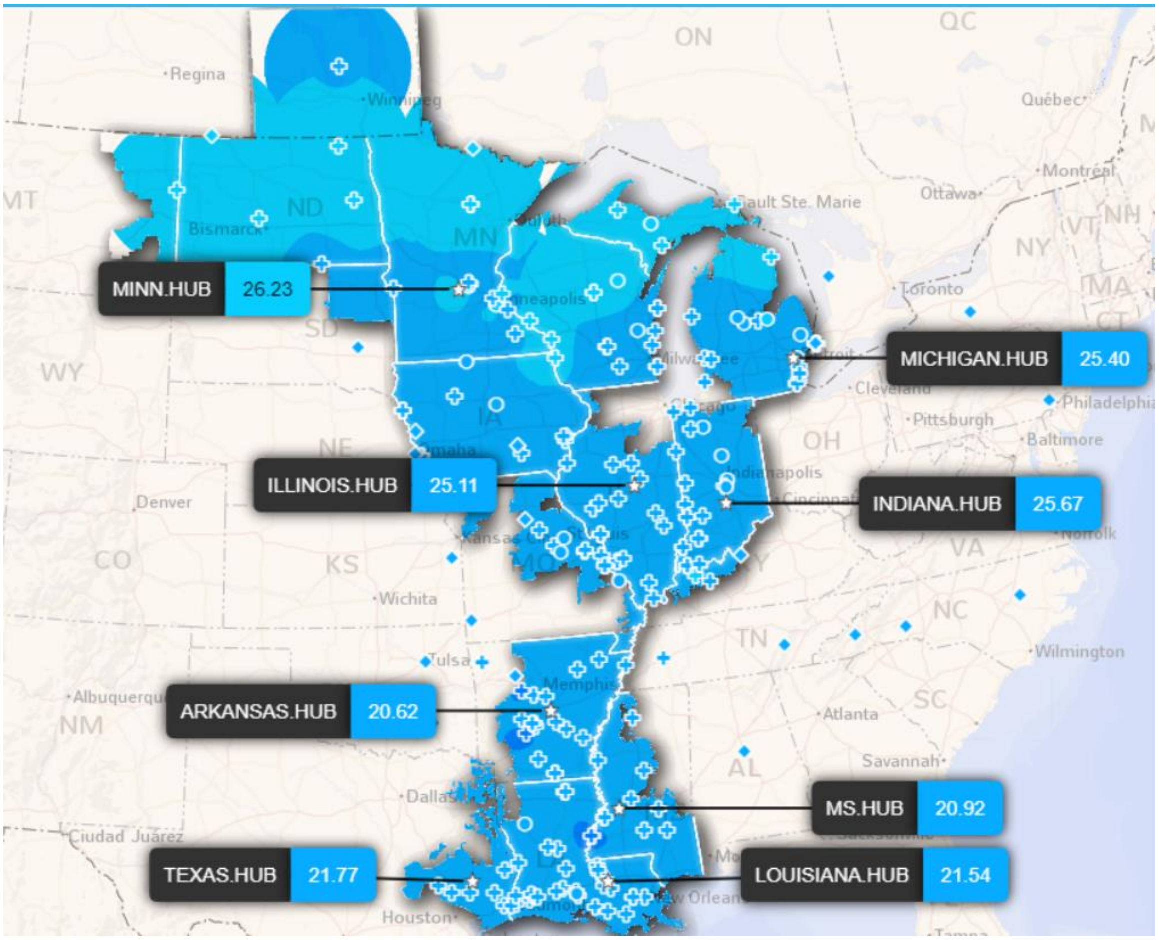


Fig. W-3: MISO LMPs at 8:45pmCT 2/10/2024

So what has happened to the PTC since 2013?

1. Renewed for 1 year by the *American Taxpayer Relief Act of 2012* (H.R. 8, Sec. 407) in Jan., 2013;
2. Renewed for 1 year by the *Tax Increase Prevention Act of 2014* (H.R. 5771, Sec. 155) in Dec., 2014;
3. Renewed by the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in Dec., 2015. However, the intent was that this would be the last renewal; the PTC would be phased out over time, from $22/Mwhr, as follows:

- For wind facilities commencing construction in 2017, the PTC amount is reduced to 80%
- For wind facilities commencing construction in 2018, the PTC amount is reduced to 60%
- For wind facilities commencing construction in 2019, the PTC amount is reduced to 40%
- For wind facilities commencing construction after 12/31/2019, no PTC will be applied

This PTC reduction schedule for wind, and the reduction schedule for the investment tax credit (ITC) on solar, is illustrated in Fig. W-4 (a figure developed by the US EIA based on the Consolidated Appropriations Act of 2016).

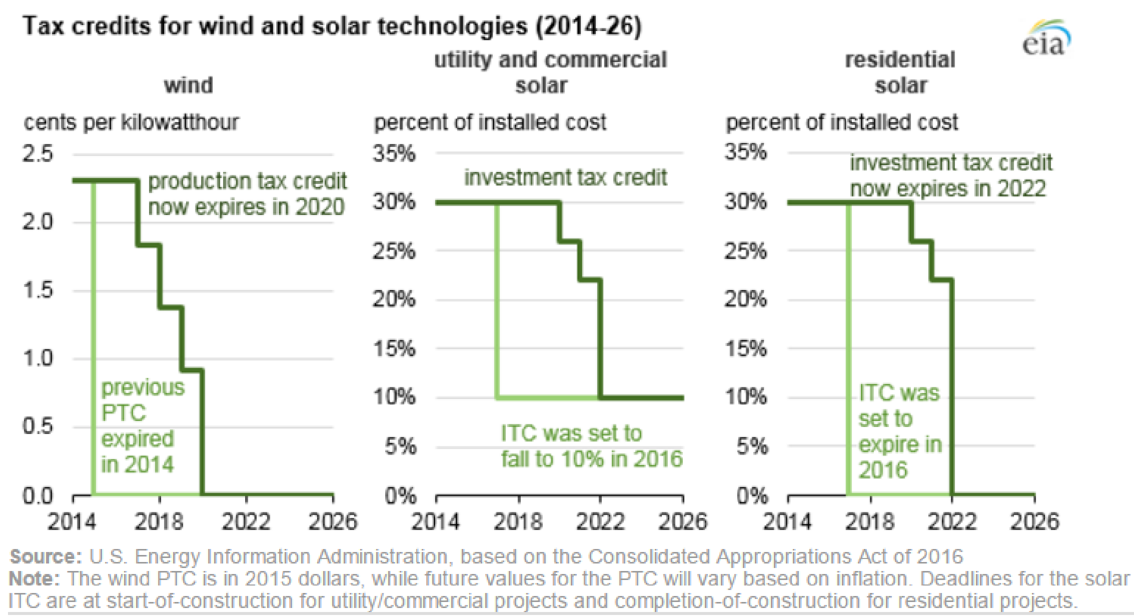


Fig. W-4: PTC reduction schedule 2014-2026

However, as a result of the high US inflation experienced in the 2020-2021 years, the 2022

Inflation Reduction Act was passed. This act, among a great many other things, extended both the PTC (increased to $27.50/MWh) and the 30% ITC through 2032, as long as projects meet prevailing wage and appreciceship requirements and exceed 1 MW [84].

Wind growth by country and by state

As indicated in Fig. W-5, globally, the US ranks 2nd in cumulative total wind capacity at the end of 2022, behind only China [85].

Cumulative Capacity (end of 2022, GW)	
China	365
United States	**144**
Germany	67
India	42
Spain	30
United Kingdom	28
Brazil	26
France	21
Canada	15
Sweden	15
Rest of World	153
TOTAL	**906**

Fig. W-5: Total wind capacity by country, 2022 [85]

As indicated in Fig. W-6 [85], wind farms have presence in almost every state (with exception of the southeast). The heaviest concentration is in the Midwest, which is a direct result of the very rich wind resource, as indicated in Fig. W-7 [85].

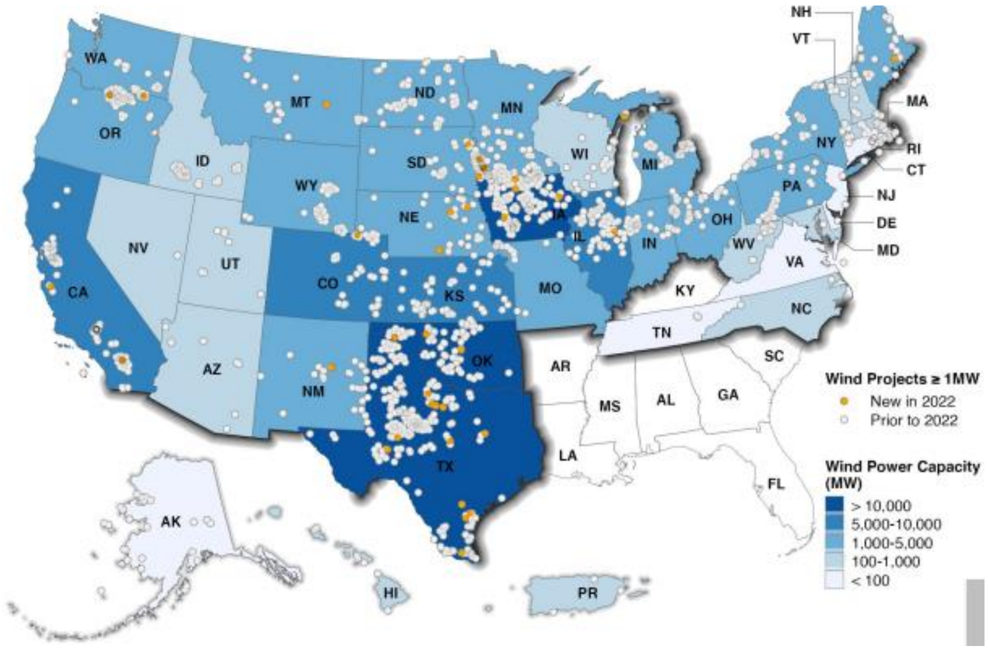


Fig. W-6: US wind farms [85]

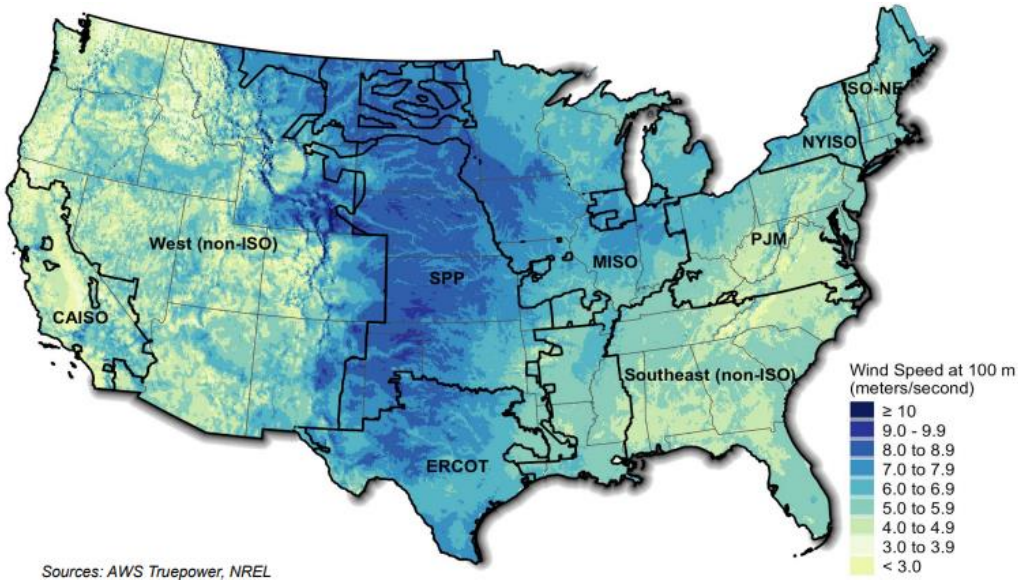


Fig. W-7: 100 m average wind speeds in US [85]

The regional indications of Figs. W-6 and W-7 can also be characterized by state, as indicated in Fig. W-8 [85], where we observe that Texas, at 40,151 MW, is far ahead of all other states by wind capacity, whereas Iowa, at 62.4%, is far ahead of all other states by percentage of in-state energy generation.

Installed Capacity (MW)				2022 Wind Generation as a Percentage of:			
Annual (2022)		Cumulative (end of 2022)		In-State Generation		In-State Sales	
Texas	4,028	Texas	40,151	Iowa	62.4%	Iowa	81.9%
Oklahoma	1,607	Iowa	12,783	South Dakota	54.8%	South Dakota	76.9%
Nebraska	602	Oklahoma	12,222	Kansas	47.0%	Kansas	69.9%
Iowa	484	Kansas	8,240	Oklahoma	43.5%	North Dakota	65.5%
Montana	366	Illinois	7,129	North Dakota	36.7%	Wyoming	60.4%
South Dakota	304	California	6,118	New Mexico	34.9%	Oklahoma	54.0%
Minnesota	245	Colorado	5,194	Nebraska	31.0%	New Mexico	52.6%
New Mexico	235	Minnesota	4,749	Colorado	28.0%	Nebraska	37.7%
Oregon	210	New Mexico	4,327	Minnesota	23.5%	Colorado	29.2%
Colorado	145	North Dakota	4,302	Maine	22.8%	Montana	25.9%
Illinois	120	Oregon	4,055	Wyoming	21.8%	Texas	25.3%
Michigan	72	Nebraska	3,519	Texas	21.6%	Maine	23.3%
California	72	Indiana	3,468	Vermont	18.2%	Minnesota	21.5%
Maine	20	Washington	3,407	Idaho	16.6%	Oregon	17.1%
		Michigan	3,231	Montana	14.8%	Illinois	16.9%
		South Dakota	3,219	Oregon	14.3%	Idaho	11.1%
		Wyoming	3,176	Illinois	12.1%	Washington	10.1%
		Missouri	2,435	Indiana	9.9%	Indiana	9.7%
		New York	2,192	Missouri	9.4%	Missouri	9.3%
		Montana	1,487	Michigan	7.8%	Michigan	9.1%
Rest of U.S.	*0*	*Rest of U.S.*	*8,769*	*Rest of U.S.*	*1.7%*	*Rest of U.S.*	*1.5%*
Total	**8,511**	**Total**	**144,173**	**Total**	**10.1%**	**Total**	**11.2%**

Fig. W-8: Installed capacity & generation by state [85]

Wind Technology

There are 9 components/sys to wind plant/turbines:

1. Turbine foundations
2. Towers
3. Nacelles
4. Gearboxes
5. Electric generators
6. Rotor hubs and blades
7. Wind farm collection circuits
8. Wind farm point of interconnection substation
9. Transmission

These components/systems are illustrated in Fig. W-9 and W-10.

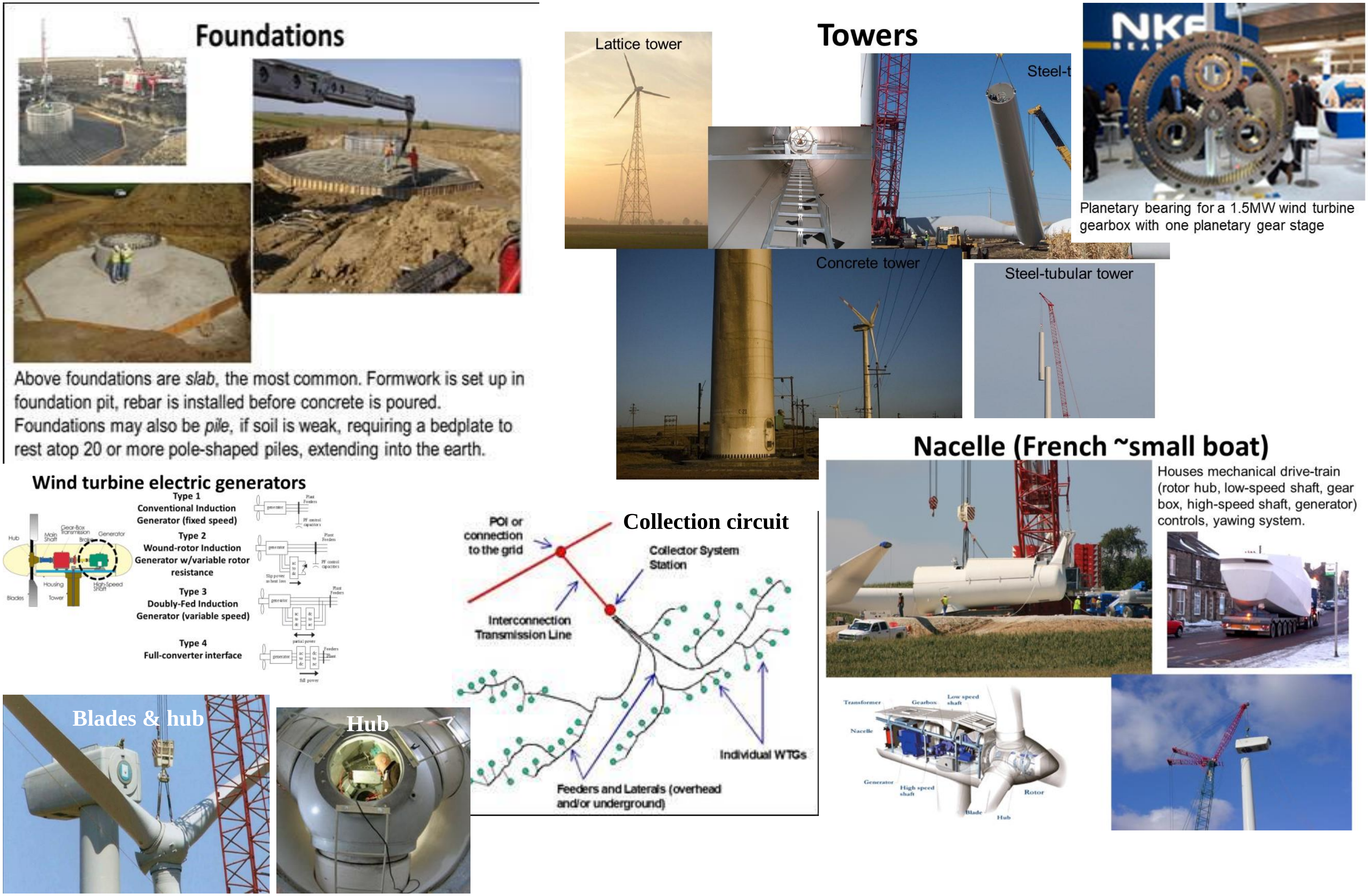


Fig. W-9: Illustration of wind turbine components and systems

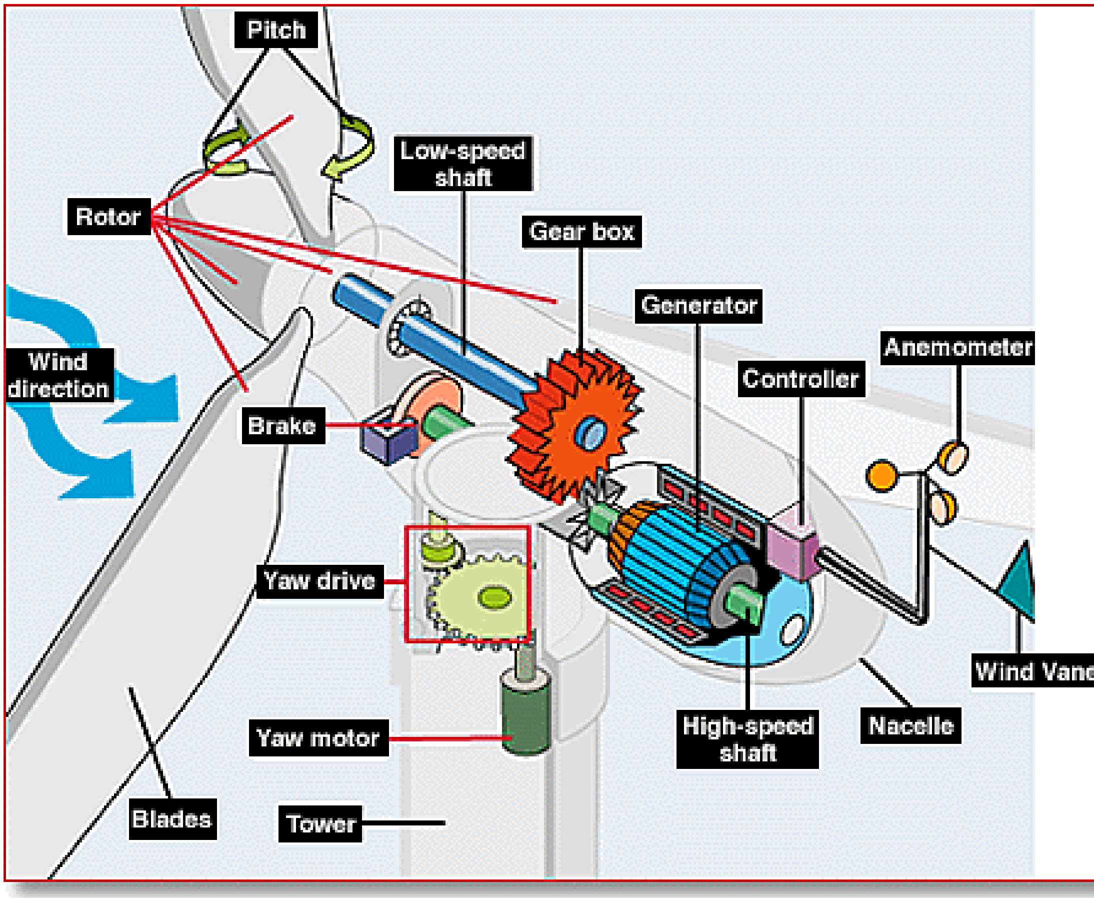


Fig. W-10: Illustration of wind turbine components

Wind challenges

There are four significant challenges to overcome in order to support large growth in wind: transmission, variability, local siting issues, and public resistance.

First, because the best wind resources in the US are located remote from load centers, moving wind energy to load invariably requires new transmission. Therefore, heavy wind energy growth must generally go hand-in-hand with the development of transmission. This is particularly the case when large blocks of wind farms are being developed. For example, in 2007-2013, the Electric Reliability Council of Texas (ERCOT), through their Competitive Renewable Energy Zones (CREZ) added 3500 transmission miles to their 345 kV system to accommodate the heavy wind growth in the Texas panhandle, see Fig. W-11. More recently, from about 2010-2021, the Midcontinent Independent System Operator (MISO) added 3655 transmission miles through their multivalue projects (MVP), see Fig. W-12, and are now studying another transmission buildout through their long-range transmission plan (LRTP) efforts, see Fig. W-13. All of these projects were/are heavily motivated by the development of wind farms. Moving forward, it is becoming increasing hard to build transmission, a major challenge for building new wind projects.

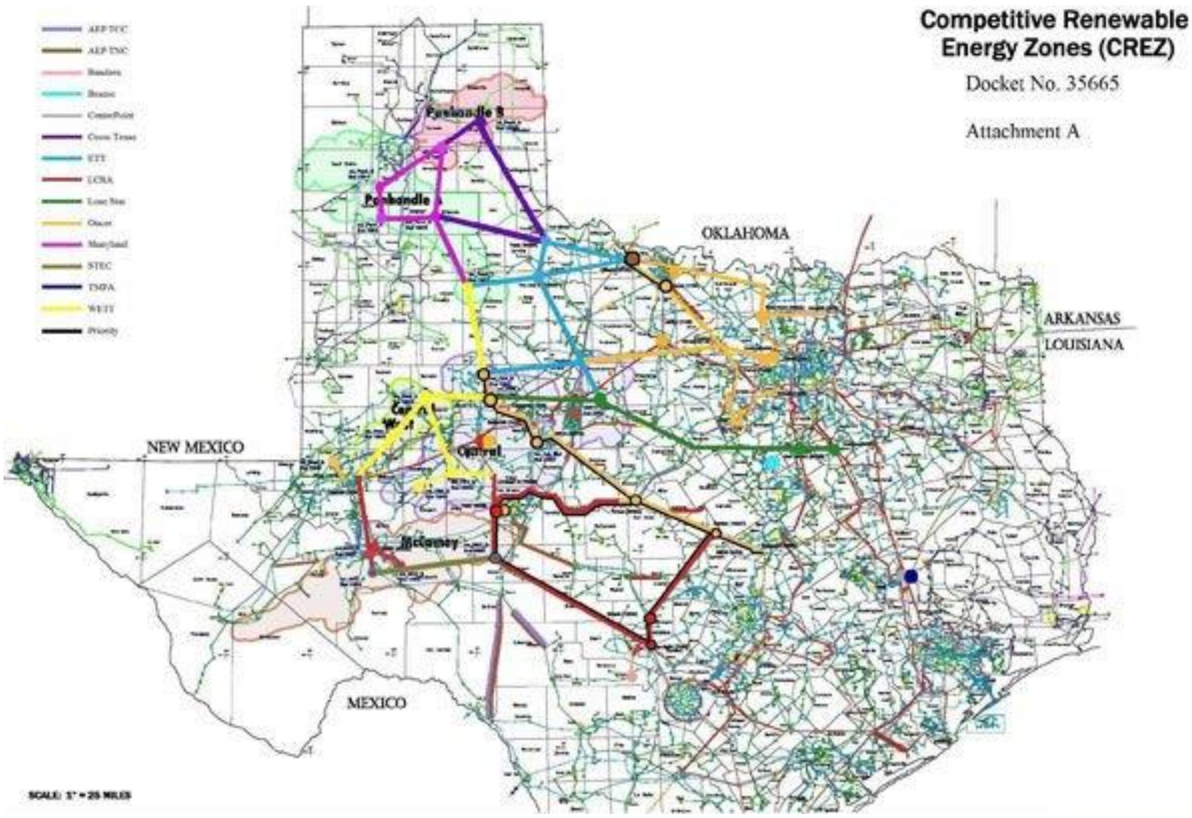


Fig. W-11: Texas CREZ lines

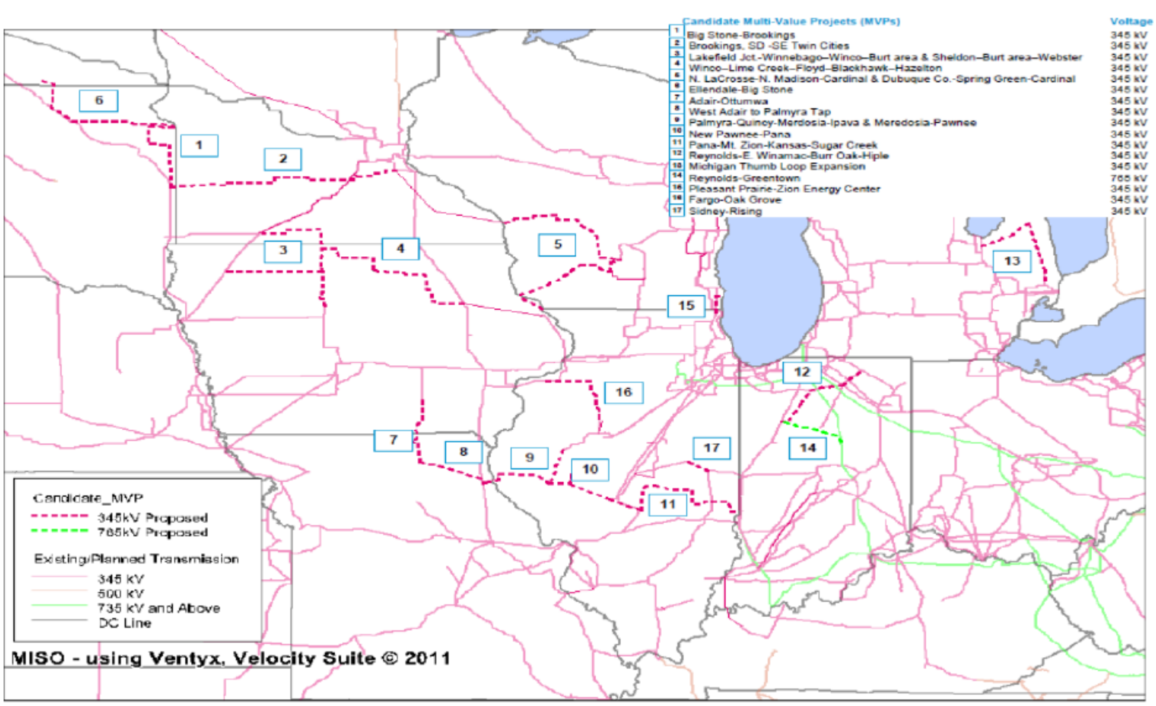


Fig. W-12: MISO MVP Lines

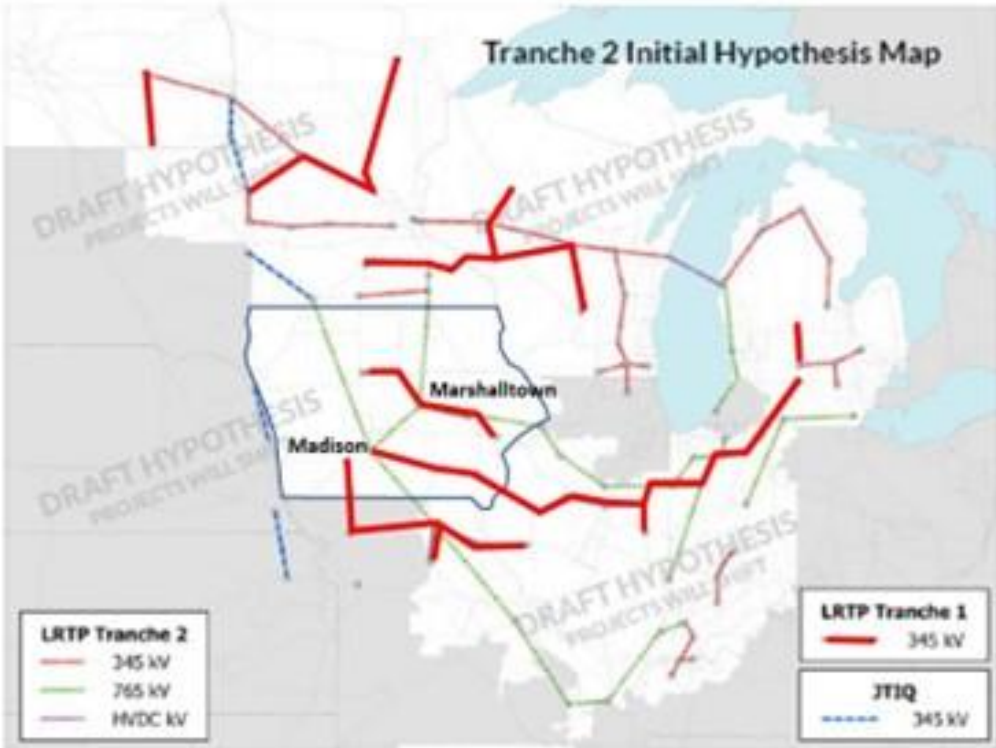


Fig. W-13: MISO LRTP Tranche 1 and 2 Lines

Regarding variability, the power grid must balance generation to load and losses on a second-by-second, minute-by-minute, and hour-by-hour basis. The difficulty has always existed, because the load varies. But wind (as well as solar) is a variable resource, meaning it increases and decreases in a way that cannot be controlled, or at least it is more difficult to control it[7]. As a result, we typically consider netload, which is the load minus the total variable resource

[7] Both wind and solar may be controlled in the downward direction, i.e., they may be reduced to something lower than the generation level that results from taking full advantage of the momentary wind speed. However, they cannot be increased beyond this generation level. In addition, there is much interest today in pairing wind (and solar) with storage, a solution which would increase controllability of wind and solar resources; however, this increases the cost of the energy.

generation. The distribution on 1-min netload variability is necessarily wider than the distribution on l-min load variability (or 1 hour, or any other time frame). The significance of this is that systems with high penetrations of variable resources must meet increased variability needs. Therefore, it is important to find economically attractive ways to balance power at the needed time frames. A great deal of work has been done to solve this problem, but most regions of the country are still at only 10-20% variable generation. The problem requires additional innovation as variable resource penetration increases to 30, 40, 50, 60, 70, 80 % and higher.

The third challenge for wind is to address local siting issues. Although the range of such issues is broad, there have been two main ones over the years: effects on wildlife - particularly birds and bats, and effects on humans – particularly visual (aesthetics), noise, and shadow flicker.

Public resistance causes an increasingly influential impediment to growing wind and solar resources. Despite the fact that these resources provide land-lease revenues to individual landowners, increased property taxes to counties, and well-paying jobs to communities, there are people who prefer not to have wind and solar farms on their land or on the land of their neighbors. Many such people are very active in making their voice heard, communicating at all levels of government. Perhaps the most significant influence of public resistance is at the state and county levels. County ordinances impose restrictions on setback. Setback is the "required boundaries around infrastructure where wind turbines cannot be installed—for property lines, buildings, roads, railroads, electric transmission lines, and bodies of water" [86]. Although such requirements are certainly needed, the level at which they are set can have considerable impact on how much wind and solar resources can be deployed in a given area.

Indeed, the National Renewable Energy Laboratory (NREL) has recently released two datasets: one including nearly 2000 US wind energy zoning ordinances, and another including nearly 1000 solar energy ordinances at the state, county, township, and city levels [86]. It is important to understand that setbacks are also "influenced by wind turbine tip heights—the taller the turbine, the larger the setback" [86] and that "Other ordinances, like noise limitations, shadow flicker limits, and utility-scale wind bans or moratoriums, are also included" in the datasets [86]. As an indication of the impact of these ordinances and zoning laws, NREL indicates that "total U.S. wind energy technical potential is seven times greater under the least restrictive siting regimes as compared to the most restrictive siting regimes." Fig. W-14 shows a section of their wind ordinance dataset, taken from [87]. Included in Fig. W-14 are eight counties in the Northwest corner of Iowa. Story County (at the bottom of the list) has also been included, since it is where Iowa State University is located.

NREL indicates that they account for these ordinances in computing their supply curves [88]; these curves show the wind energy potential in a selected region of each state.

State	City/Town	County	Feature Type	Value Type	Value	Citation	Comment	Original Captured Da	New Capture Da	Update Status
Iowa		Cherokee	Structures	Meters	381	Cherokee County Ord. 2017-01 § 4		2018	2021	No change
Iowa		Cherokee	Sound	dBA	50	Cherokee County Ord. 2017-01 § 4		2018	2021	No change
Iowa		Cherokee	Property Line	Max tip-height Multiplier	1.1	Cherokee County Ord. 2017-01 § 4		2021		
Iowa		Cherokee	Transmission	Max tip-height Multiplier	1.1	Cherokee County Ord. 2017-01 § 4		2018	2021	No change
Iowa		Clay	Structures	Max tip-height Multiplier	365.76	Clay County Code § 17.7.2	1200' setback to residences	2021		
Iowa		Clay	Property Line	Max tip-height Multiplier	1.1	Clay County Code § 17.7.2		2021		
Iowa		Clay	Transmission	Max tip-height Multiplier	1.1	Clay County Code § 17.7.2		2021		
Iowa		Dickinson	Structures	Max tip-height Multiplier	2	Dickinson County Code § 21.5(D)	Greater of 2x max tip height or 1200'	2021		
Iowa		Dickinson	Rivers/Lakes	Meters	201	Dickinson County Code § 21.5(D)	660' setback to "public waters"	2021		
Iowa		Dickinson	Roads	Max tip-height Multiplier	1.1	Dickinson County Code § 21.5(D)		2021		
Iowa		Dickinson	Transmission	Max tip-height Multiplier	1.1	Dickinson County Code § 21.5(D)		2021		
Iowa		Lyon	Structures	Meters	381	Lyon County Zoning Ord. § 18.8.2		2021		
Iowa		Lyon	Property Line	Max tip-height Multiplier	1.1	Lyon County Zoning Ord. § 18.8.2		2021		
Iowa		Lyon	Roads	Max tip-height Multiplier	1.1	Lyon County Zoning Ord. § 18.8.2		2021		
Iowa		Lyon	Transmission	Max tip-height Multiplier	1.1	Lyon County Zoning Ord. § 18.8.2		2021		
Iowa		O'Brien	Roads	Max tip-height Multiplier	1.2	O'Brien Wind Energy Device Ord. 22 § 4		2018	2022	No change
Iowa		O'Brien	Structures	Meters	365.76	O'Brien Wind Energy Device Ord. 22 § 4		2018	2022	No change
Iowa		Osceola	Structures	Meters	381	Osceola County Zoning Ord. § 13.3.2		2022		
Iowa		Osceola	Sound	dBA	50	Osceola County Zoning Ord. § 13.3.12		2022		
Iowa		Osceola	Property Line	Max tip-height Multiplier	1.1	Osceola County Zoning Ord. § 13.3.2		2022		
Iowa		Osceola	Roads	Max tip-height Multiplier	1.1	Osceola County Zoning Ord. § 13.3.2		2022		
Iowa		Plymouth	Structures	Max tip-height Multiplier	2	Plymouth County Zoning Ord. § 6.10(B)		2018	2022	No change
Iowa		Plymouth	Roads	Max tip-height Multiplier	1.1	Plymouth County Zoning Ord. § 6.10(B)		2022		
Iowa		Plymouth	Transmission	Max tip-height Multiplier	1.1	Plymouth County Zoning Ord. § 6.10(B)		2022		
Iowa		Sioux	Structures	Max tip-height Multiplier	2	Sioux County Zoning Ord. § 27.14.5	Greater of 2x Max tip height or 1000'	2022		
Iowa		Sioux	Sound	dBA	60	Sioux County Zoning Ord. § 27.14.5		2022		
Iowa		Sioux	Railroads	Max tip-height Multiplier	1.1	Sioux County Zoning Ord. § 27.14.5		2022		
Iowa		Sioux	Transmission	Max tip-height Multiplier	1.1	Sioux County Zoning Ord. § 27.14.5		2022		
Iowa		Story	Structures	Max tip-height Multiplier	2	Story County Land Use Regs. § 90.08.5		2018	2022	No change
Iowa		Story	Sound	dBA	60	Story County Land Use Regs. § 90.08.5		2018	2022	No change
Iowa		Story	Transmission	Max tip-height Multiplier	1.1	Story County Land Use Regs. § 90.08.5		2018	2022	No change
Iowa		Story	Railroads	Max tip-height Multiplier	1.1	Story County Land Use Regs. § 90.08.5		2022		

Fig. W-14: Sample from the NREL Wind Ordinance Dataset [87]

10.0 Offshore wind

The offshore wind potential in the US is significant, with areas of possible development on the East Coast, the West Coast, the Gulf of Mexico, and the Great Lakes. However, at this time, as indicated in [89], "There were only two small offshore wind projects operating in the U.S. at the start of 2023, one in Rhode Island and another in Virginia, with total capacity of just 41 megawatts (MW)." Yet, the same article indicates that "Capacity is set to jump to almost 1,000 MW in 2024 as commercial-scale projects off New York and Massachusetts enter service." One reason why offshore wind has not grown significantly in the US (yet) is that, as of 2023, EIA data [90] indicates its average overnight and fixed O&M costs are 3.2 and 4.2 times that of onshore wind, respectively. Yet, offshore wind is attractive to coastal states as hold promise for economic development and job creation.

Beyond 2024, in the near-term, the Biden Administration has targeted a 30 GW goal for the nation [91], and the state of New York targets 9 GW by 2035 [92]. The states of New York, Virginia, Massachusetts, North Carolina, New Jersey, Connecticut, and Maryland in total have a 23.7 GW target by 2035 which increases to 39.3 GW by 2040 [93]. California has a target of reaching 25 GW (floating) by 2045 [94]. A longer-term target has also been communicated by the Biden administration of reaching 110 GW by 2050 [95].

Despite these aggressive public goals, and although worldwide investment in offshore wind was very healthy in 2023 (see Fig. O-1 [96]), US activities faltered in that over 12 GW of US offshore wind contracts were either canceled or targeted for renegotiation in 2023 [97], due to “rising equipment and financing costs, permitting and grid connection hurdles, and supply chain delays” [96]. The reason for this US slow-down is that contracts for selling the energy must be locked in 2-3 years in advance, and the inflation of the 2019-2022 years caused unexpected increases in cost of important materials such as steel [97].

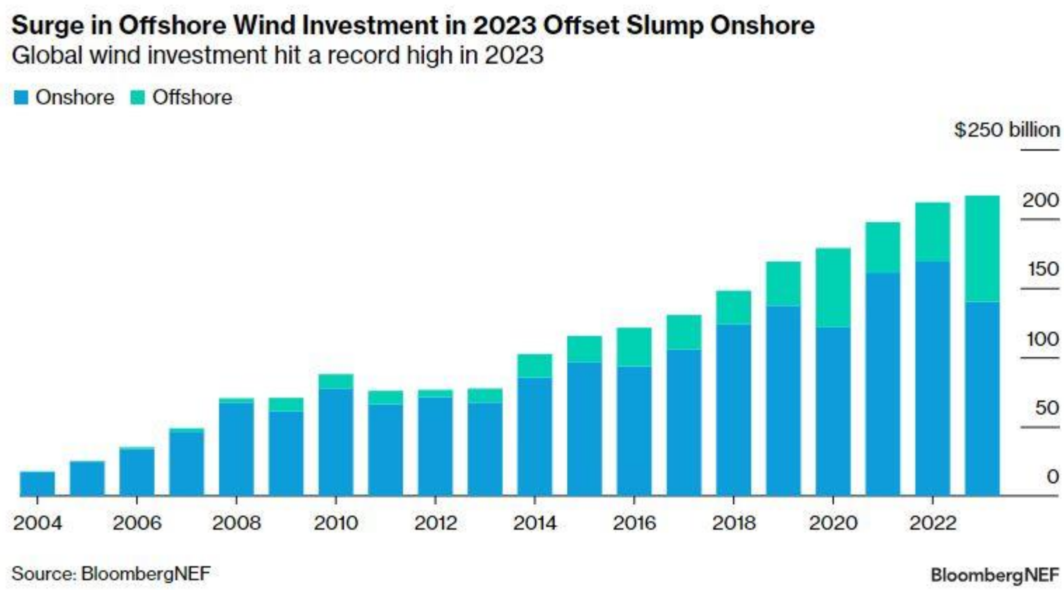


Fig. O-1: Worldwide onshore & offshore wind investment [96]

The process of offshore wind development is complex. It is largely orchestrated by the US Bureau of Ocean Energy Management (BOEM). It consists of at least the following steps:

1. Planning and analysis
2. Leasing
3. Site assessment
4. Construction and operation

These steps, together with, for each step, the approximate time required and the activities, are illustrated in Fig. O-2 [98]. A key step in the process is the auction for leases, where entities interested in leasing an area compete within an auction; auction format and rules may be found at [99].

Fig. O-2: Process of offshore wind development [98]

Figure O-3 indicates the offshore wind capacity at different stages of the process, as of May, 2023 [100].

Status	Description	Total (Megawatts)
Operating	The project is fully operational with all wind turbines generating power to the grid.	42
Under Construction	All permitting processes completed. Wind turbines, substructures, and cables are in the process of being installed. Onshore upgrades are underway.	932
Financial Close	All permitting processes completed; begins when sponsor announces final investment decision and has signed contracts.	0
Approved	Bureau of Ocean Energy Management (BOEM) and other federal agencies reviewed and approved a project's Construction and Operations Plan (COP). The project has received all necessary state and local permits as well as acquired an interconnection agreement to inject power to the grid.	1,100
Permitting	The developer has site control of a lease area, has received an offtake contract or submitted a COP to BOEM, and BOEM has published a Notice of Intent to prepare an Environmental Impact Statement on the project's COP. If project development occurs in state waters, permitting is initiated with relevant state agencies.	20,978
Site Control	The developer has acquired the right to develop a lease area and has begun surveying the site. If available, developers' announced project capacities are used. If a developer has not announced a specific capacity, it is estimated using a 4-MW/km^2 wind turbine density.	24,596
Planning	The rights to a lease area have yet to be auctioned to offshore wind energy developers. Capacity is estimated using a 4-MW/km^2 wind turbine density assumption.	5,039

Fig. O-3: Offshore wind capacity at each stage, 2023 [100]

Fig. O-4 gives offshore wind capacity at each stage, by state, where it is observed that New York, New Jersey, and Massachusetts account for over half of the US offshore wind capacity in the pipeline as of 2023 [100].

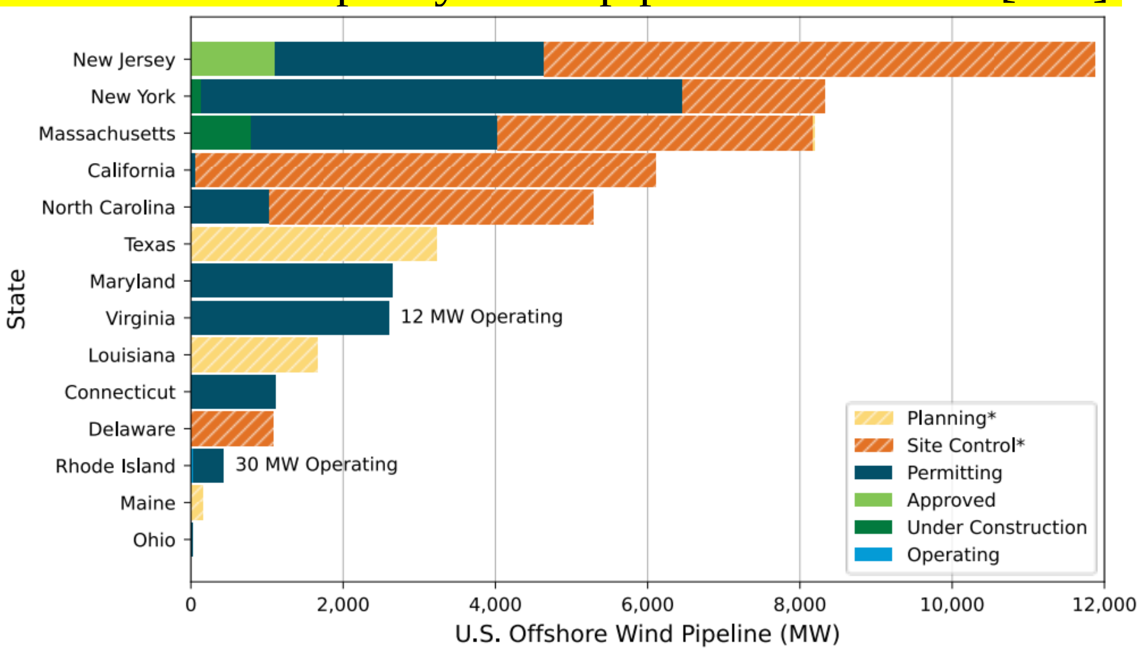


Fig. O-4: Offshore wind capacity at each stage, by state 2023 [100]

A key influence on the economics of deploying offshore wind energy is, at the location of deployment, the distance from shore (affects transmission cost) and the bathymetry or depth of the ocean (affects turbine foundation cost). Fig. O-5 illustrates bathymetry depth in meters for the major offshore wind regions of the US [101]. It is clear that the East Coast and the Gulf Coast have a depth that is significantly shallower than that of the West Coast. Because Gulf Coast has a very large amount of offshore oil and natural gas infrastructure, and the East Coast has none of this, activities to grow offshore wind in the East Coast have received more attention so far.

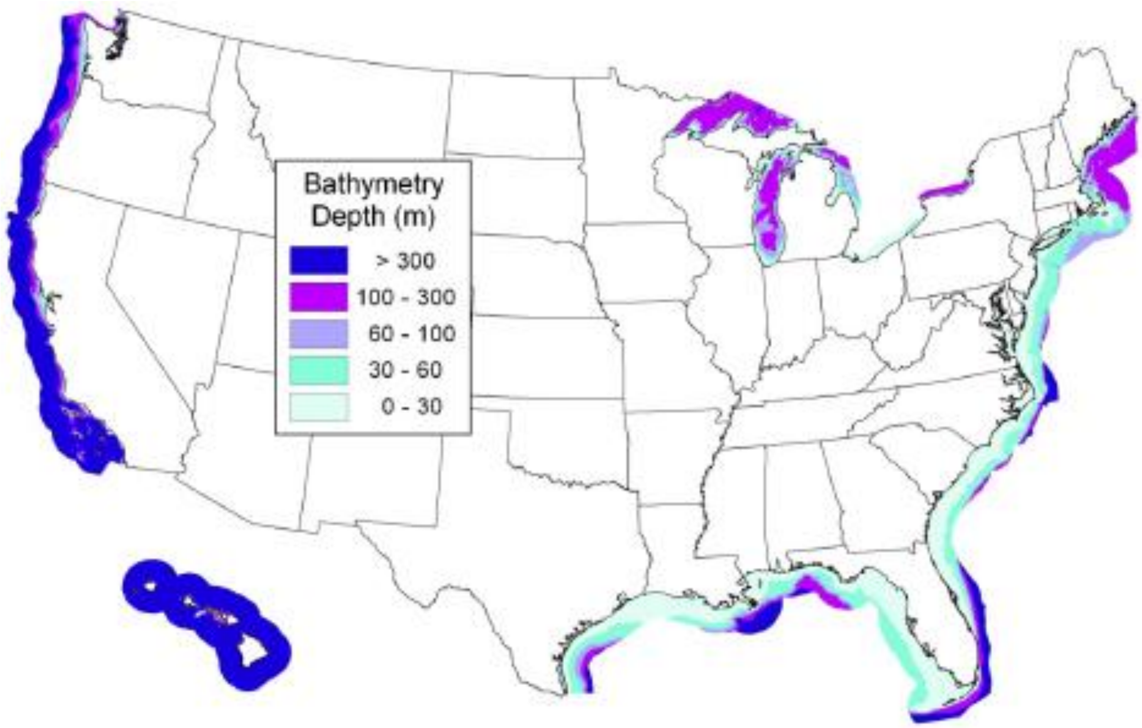


Fig. O-5: Bathymetry along the US coastlines

The most important offshore wind design feature influenced by water depth is whether the turbine is fixed or floating. Fixed turbines have a rigid connection to the seabed, via either monopiles, jacket, or gravity-based foundations (see Fig. O-6); they are the least-cost option for depths significantly below 60 meters. Floating turbines are moored to the seabed using offset anchors or foundations (see Fig. O-7 [102]) and mooring lines and are generally the least-cost option for depths significantly above 60 meters.

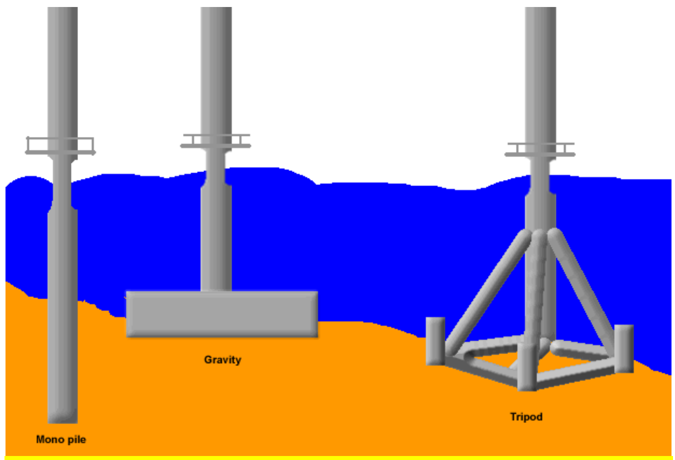


Fig. O-6: Fixed turbine designs

Fig. O-7: Floating (left) & fixed (right) turbine designs [102]

Offshore wind technologies

Whereas onshore wind is limited by the base of the tower that will fit under highway underpasses, offshore wind can be moved by barge and so is not affected by this constraint. As a result, offshore wind turbines can have much larger capacity ratings than onshore wind turbines. Reference [103] indicates that

- whereas the largest commercially deployed onshore wind turbines are about 6 MW (the GE Cypress is 6 MW, the Vestas V162-6 is 6.2 MW);
- the largest commercially deployed offshore wind turbines range from 10 MW (the MHI-Vestas V164-10.0 is 10 MW, there are three Chinese manufacturers of 11 or 12 MW turbines) to 13 MW (the GE Haliade-X is 13 MW);
- and there are prototypes and concepts for offshore turbines between 14 and 22 MW.

The GE-Haliade-X has 107-meter blades with rotor diameter of 220 meters, with height from water line to maximum blade tip of 260 meters [104]. It also advertises a capacity factor of between 60-64%, illustrating benefits of offshore wind relative to onshore wind: although they have higher capital cost, they are higher (and are able to access the higher wind speeds available at the increased heights), and they operate under ocean winds which tend to be higher and steadier than onshore winds. Fig. O-8 illustrates the dimensions of four of the largest offshore wind turbines today [105].

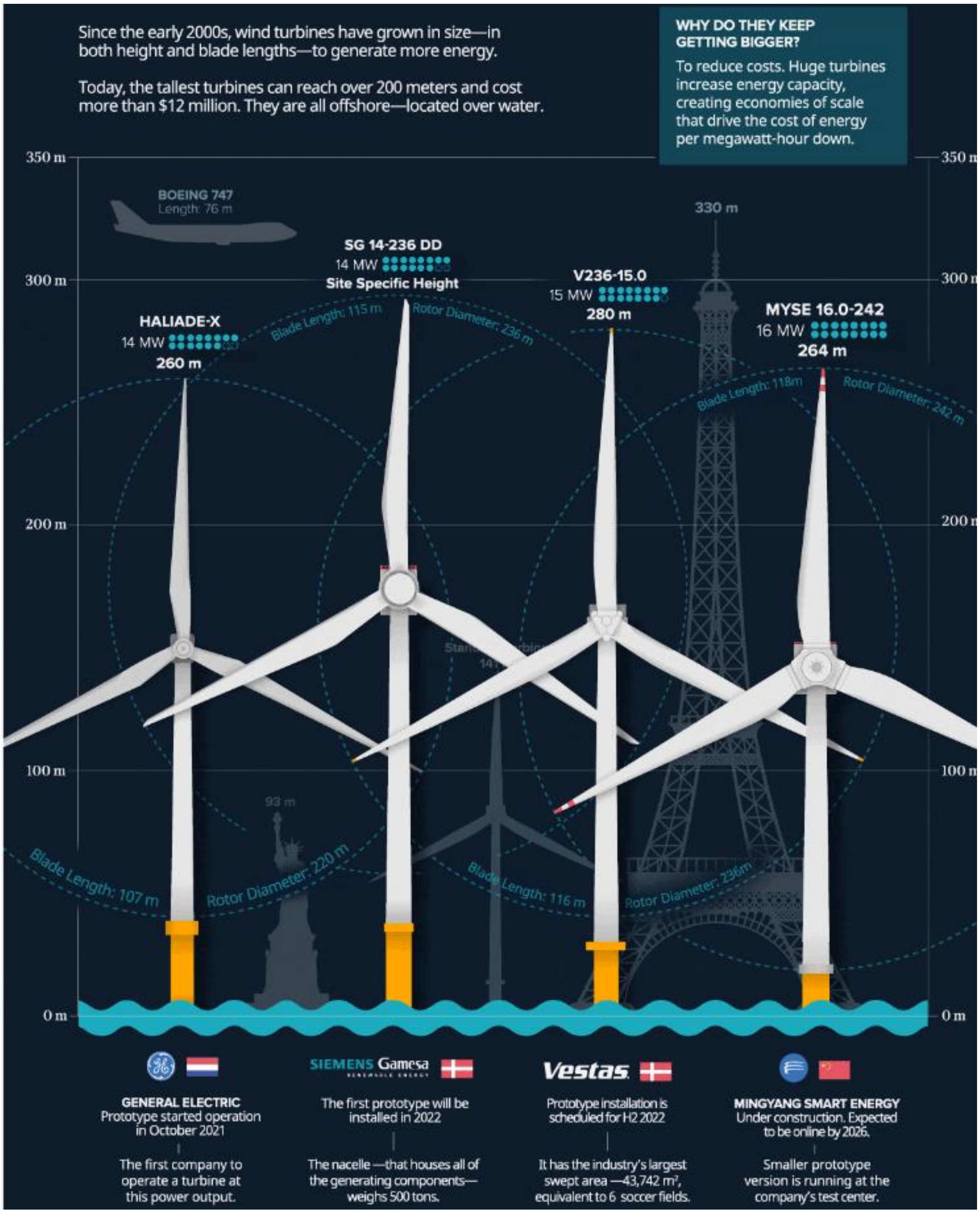


Fig. O-8: Illustration of largest offshore turbines [105]

11.0 Utility scale solar PV plants

As indicated in Section 9.0, one of the first large-scale US wind farms was in California. Likewise, the first large-scale US solar farm was also in California (and both within the PG&E service area). Built in 1983, the 5.2 MW capacity plant operated until 1994 [106]. Until about 2010, there was very little PV solar development in the US because the cost of PV panels was so high (see Table 1 in the notes "CostData" which gives the 2008 overnight cost of solar PV as being as $5649/kW, the highest cost technology given in the table, and 3.9 times the overnight cost of wind).

As of 2023 Q3, the US had 83,173 MW (83 GW) of solar PV capacity, as shown in Fig. S-1 [82]. At 3.4% (in 2022), wind energy produces the fourth most zero-carbon energy in the US today (first is nuclear at 19%; second is wind at 10%, third is hydro at 6%).

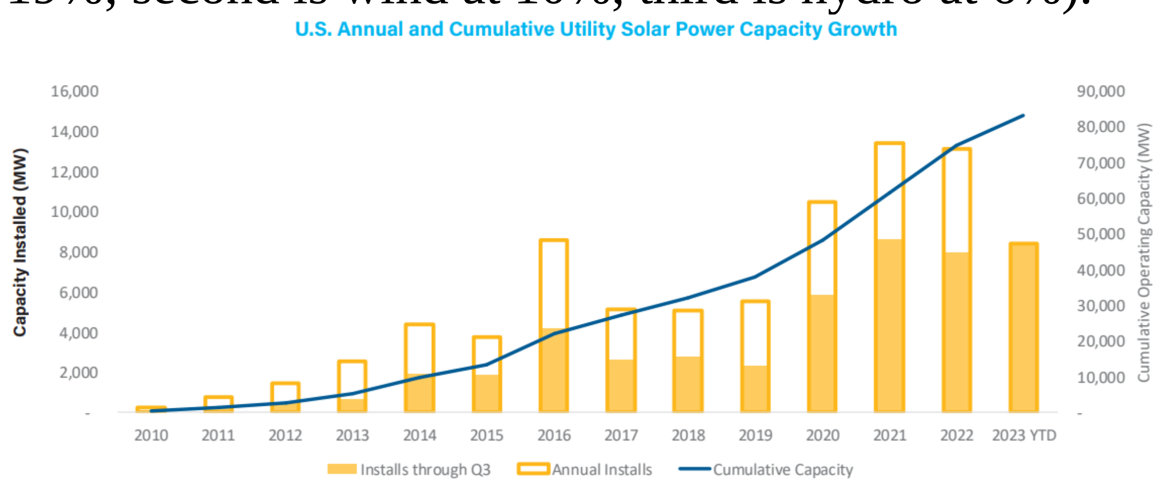


Fig. S-1: Growth of US PV Solar Capacity since 2010

Solar subsidies

As of 2006, the federal subsidy for solar projects was the the investment tax credit (ITC), which provided a 30% tax credit for solar projects. This subsidy was provided because of the high capital costs of solar PV projects at that time. The PTC was unavailable to PV solar plants. As indicated in Fig. W-4 of Section 9.0, repeated below for convenience, the ITC was set to fall to 10% in 2016 when the Consolidated Appropriations Act of 2016 extended it to 2022.

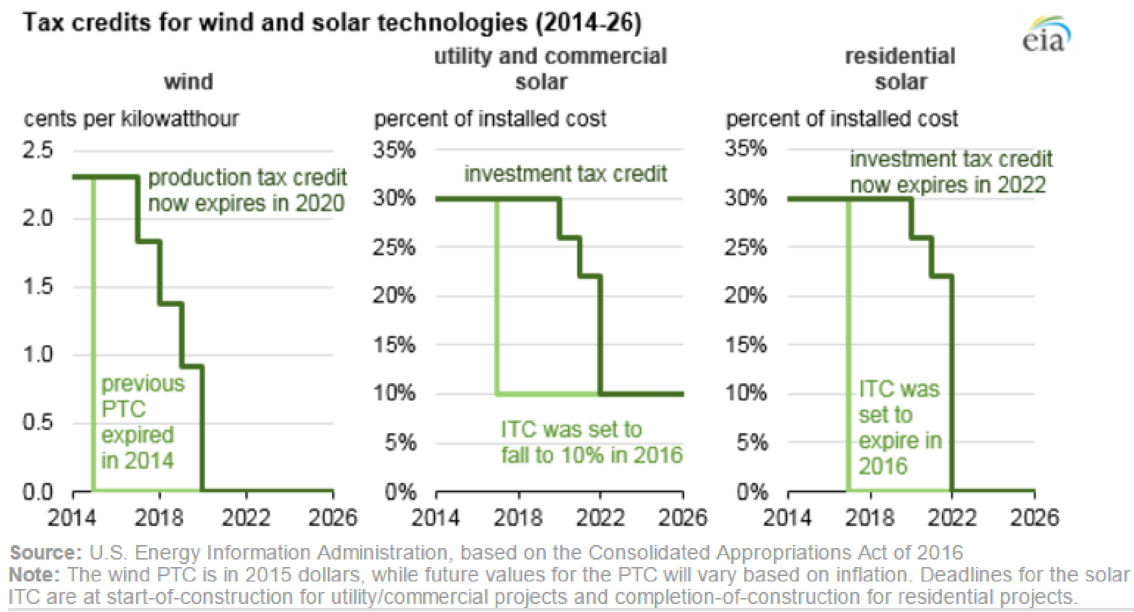


Fig. W-4: PTC reduction schedule 2014-2026

In 2022, the Inflation Reduction Act extended both the PTC and the ITC (or similar technology-neutral zero carbon emission PTC/ITC credits); in addition, it made PTC available to solar plants [107]. Given the much lower capital cost of solar PV today relative to the 2006-2020 period, and given that a plant must take either PTC or ITC (but not both), it appears that most new solar plants will tend towards the PTC in the future, although there is some situations where a solar plant may still elect to take the ITC because of its more immediate payback relative to the PTC [108].

Solar PV growth by state and by country

The top solar-PV US states are shown in Fig. S-2 [109].

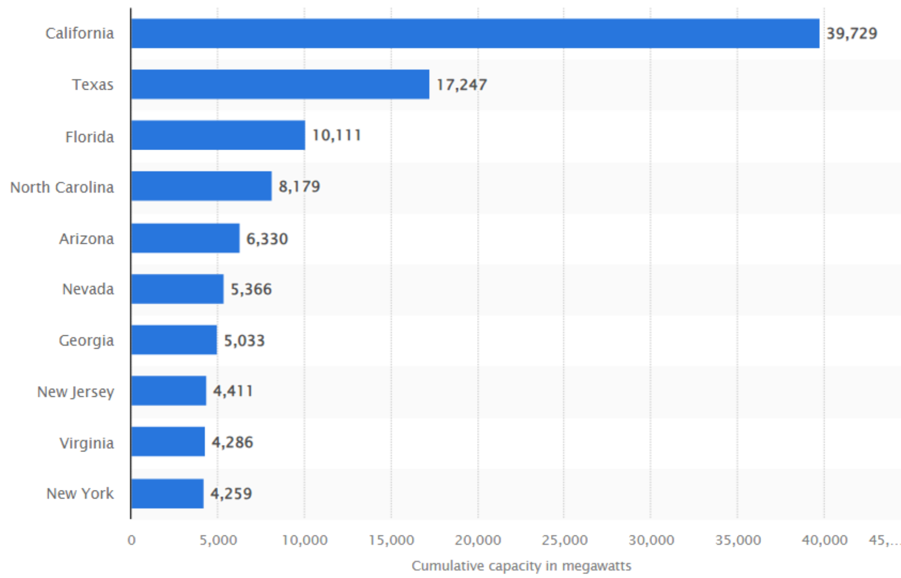


Fig. S-3: Top solar PV states, 2022 [109]

Solar PV growth worldwide, by continent (including US and China), is shown in Fig. S-2 [110].

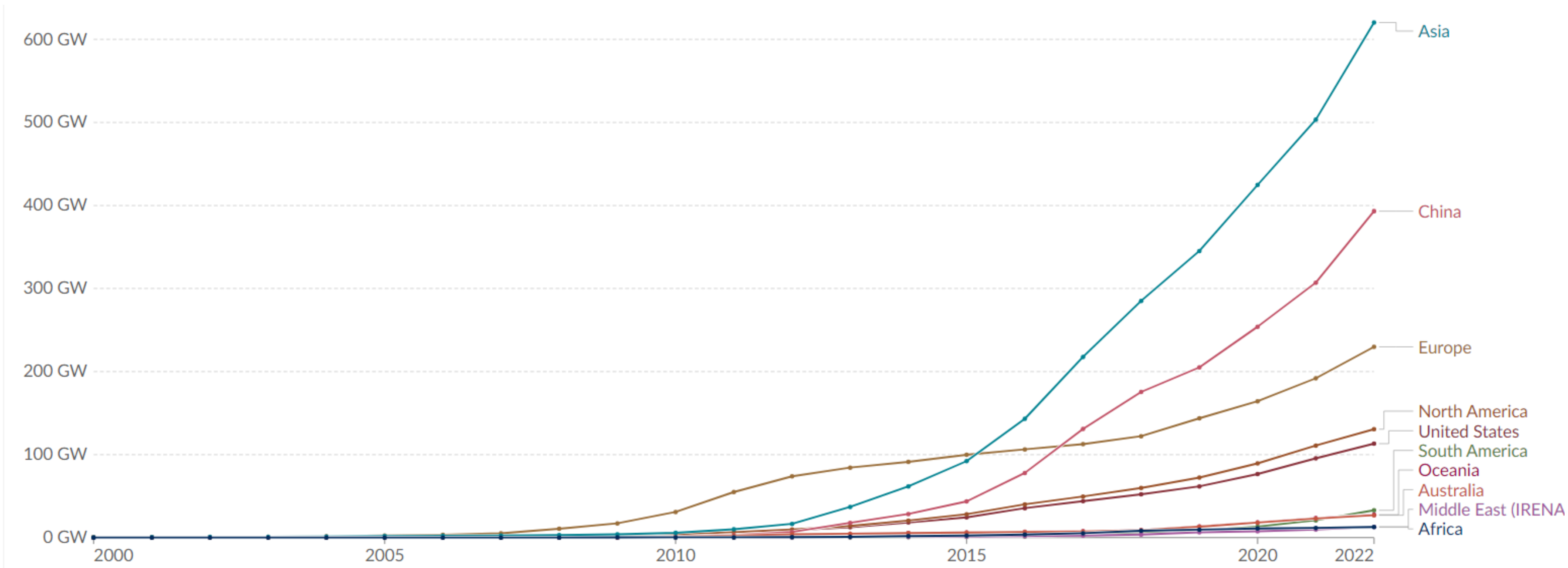


Fig. S-2: Solar PV growth by continent

Solar PV Technology

Solar technology may be divided by solar cell technology, by tracking capability, and by application.

Solar cell technology

Solar panels are comprised of solar cells; these solar cells may be crystalline silicon or thin film. Crystalline silicon solar cells were developed the earliest and can be divided into two types: monocrystalline and polycrystalline. Monocrystalline solar cells are more costly than polycrystalline but are more efficient. Both types were deployed in the first few years of solar PV development, but monocrystalline solar cells is the most commonly chosen technology today.

Thin-film solar cells are less costly than crystalline solar cells but are also significantly less efficient; as a result, they have not been heavily used in ground-mounted or rooftop applications (and so are not usually considered for utility, community, or rooftop purposes). Their attractive feature is that they are much lighter than crystalline solar cells and so are an attractive option for vehicular applications. They can be of higher interest when integrating solar PV onto building structures that require panel flexibility, e.g., on the sides of buildings.

Application

Solar panels may be deployed at so-called utility-scale, where a very large number of solar panels are ground mounted in rows. In the past, the presence of the panels made it difficult to use the land for other purposes, but there have been recent efforts to expand the field of agrivoltaics to enable collocating solar PV plants with agricultural or horticultural activities.

Solar panels may also be deployed on the roofs of residential, commercial, or industrial facilities, resulting in the term of rooftop solar. Some towns have invested in community solar, which tends to be ground-mounted and therefore similar to utility-scale except generally smaller in capacity. It is common to refer to residential, commercial, industrial, and community solar PV as “distributed solar.”

As indicated in Fig. S-3 [111], Lazard’s most recent LCOE analysis indicates that rooftop residential is the most expensive way to deploy solar PV, followed by community and commercial/industrial rooftop, with utility scale being the least cost approach. Although rooftop residential is significantly more expensive than the other types, subsidies provide that it can be an economically attractive approach to reduce energy costs for some homeowners.

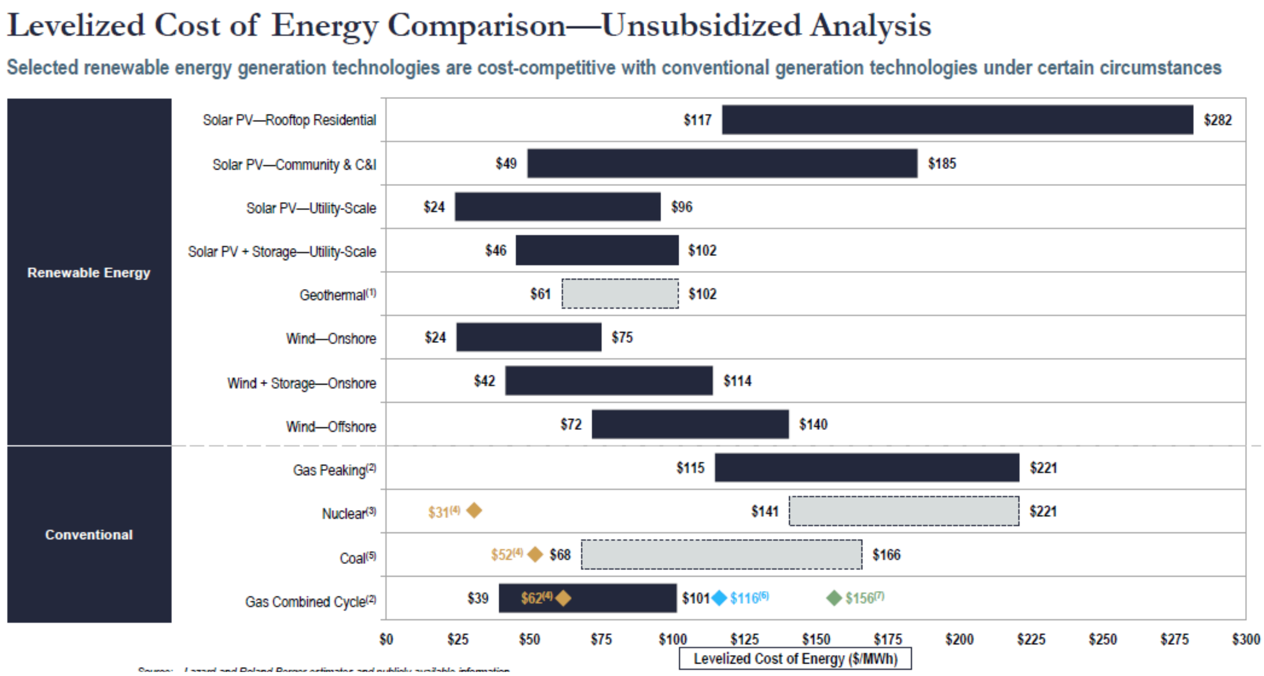


Fig. S-3: Lazard's LCOE analysis [111]

Fig. S-4 shows the US growth of solar-PV 2010 to 2023, with projected growth in 2024 [112], from which we make the following observations:

1. In 2023 and the projected 2024, solar PV [utility-scale (UPV) and distributed (DPV)] comprises the largest single investment capacity of all electric resource technologies.
2. The major portion of the solar-PV investment in 2023 and 2024 is in utility-scale.

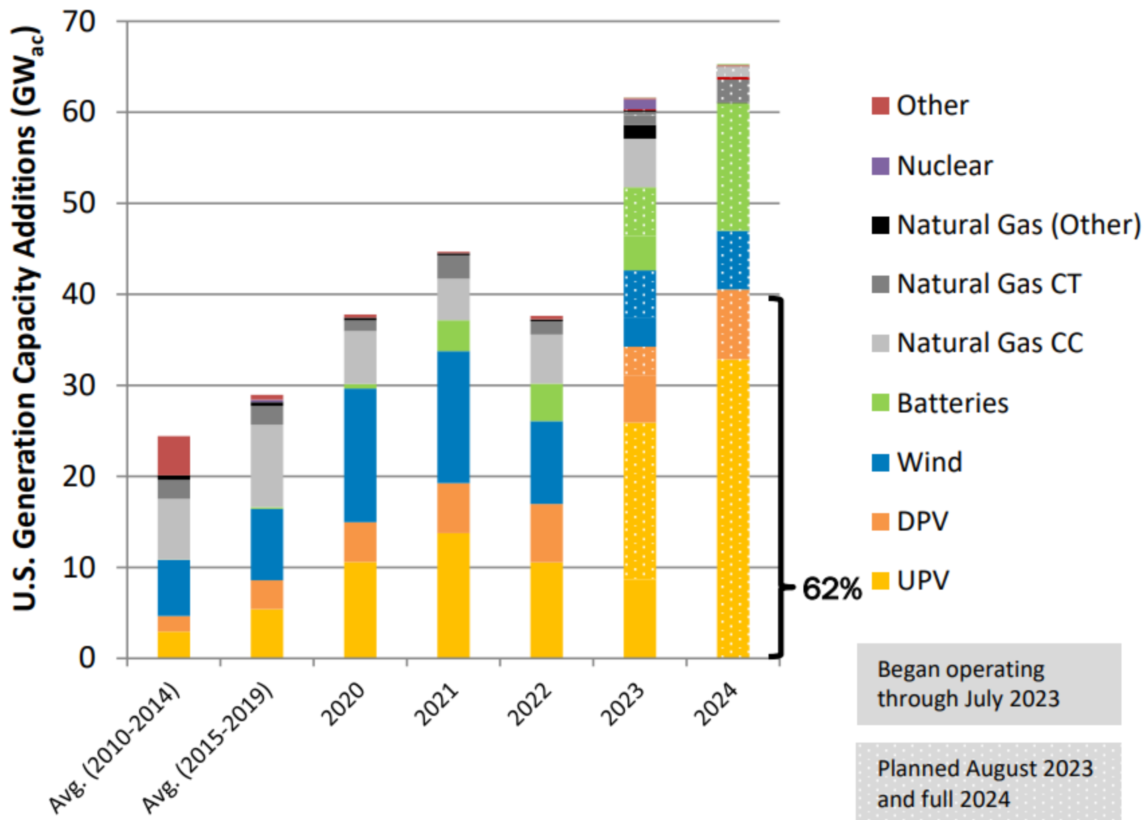


Fig S-4: Growth of solar PV from 2010, by application [112]

Tracking capability

All utility scale solar plants are ground-mounted. The earlier utility-scale solar plants were fixed tilt, where the panels are mounted at a fixed angle and orientation, typically facing south to maximize sunlight exposure. In contrast, solar PV with tracking provides that the panels may be reoriented throughout the day as the sunlight changes its angle of incidence on the earth, to keep the surface of the PV panel perpendicular to direction of the solar radiation beam [113]. Solar trackers cane be passive or active. Passive solar trackers do not use mechanical drives but rather reorients the panel as an actuator expands or contracts as a function of heat from solar radiation. In contrast, active solar trackers have radiation-triggered sensors that control an actuator to follow the sun. In 2022, 94% of new US utility-scale solar PV plants used tracking [112]. Trackers may be single axis, providing just one degree of freedom, or they may be dual-axis, providing two.

12.0 Enhanced geothermal (note: section needs updating)

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. G-1 [114].

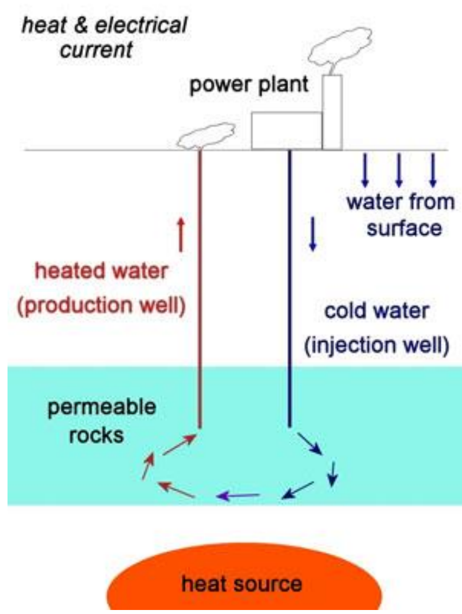


Fig. G-1: Basic EGS design

EGS plants have no emissions. More than 100 GW of power is estimated available in the U.S. EGS cost estimates were very high in the early 2000's [115] but have decreased significantly over the past 15 years; the latest (2023) EIA cost data (see notes called "CostData") indicates its overnight cost is only is only \$3403/kW (comparable to the \$3140/kW overnight cost of natural gas combined cycle units with carbon-capture and sequestration, much less than the \$8349/kW for nuclear, but significantly more than the \$2098/kW for onshore wind). However, its \$154/kW-year fixed O&M costs is the highest of any technology in the 2023 EIA cost data. Scalability depends on the source quality, as steam handling equipment is well-developed; well depth is currently limited to 30,000 ft.

Figure G-2 [115] 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.

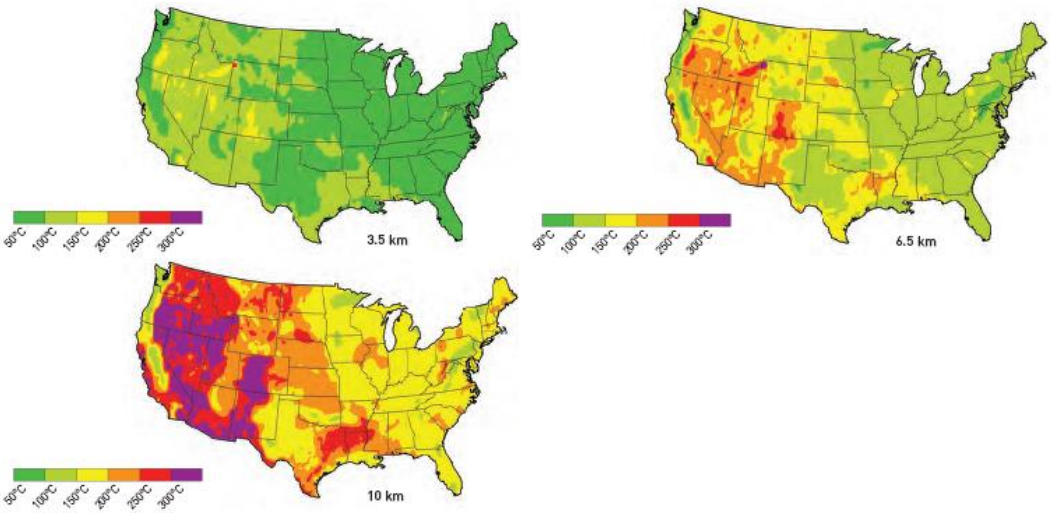


Fig. G-2: US underground temperature gradients

Fig. G-3 [115] illustrates capital cost of wells as a function of depth, in comparison to oil/gas well costs.

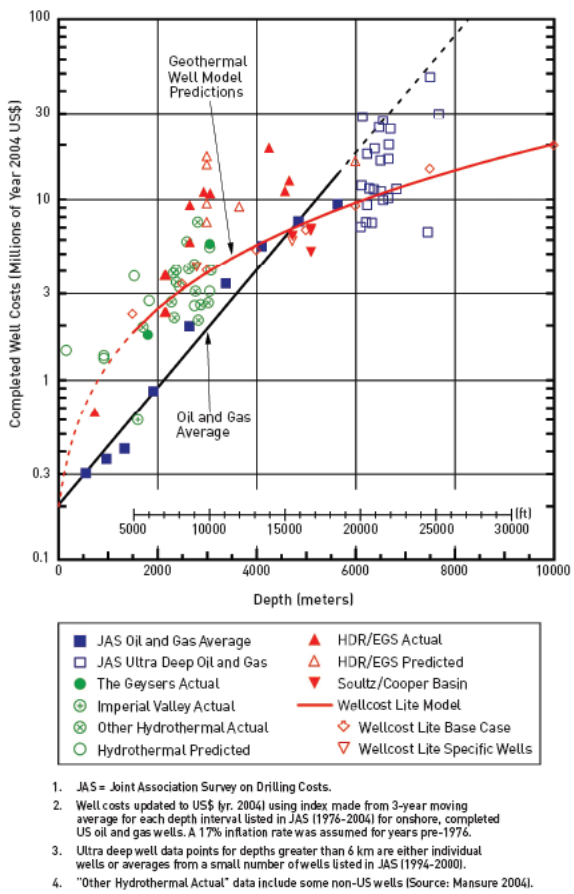


Fig. G-3: Capital cost of wells

13.0 Biomass

14.0 Distributed energy resources

15.0Other energy conversion technologies

17.0 RTO generation interconnection queues

A new generation project developer must apply for analysis and eventual interconnection, a process that requires significant human resources, most of which must be provided by RTO engineering staff. Funds for these efforts are provided via fees paid by project developers. This is a necessary step that is complex because of the interdependency among projects, the scarcity of transmission, the high cost to the developer of any needed transmission expansion, and the tendency of developers to withdraw projects at various stages of the process.

Fig. R-1 shows the growth of resource capacity in RTO generation interconnection queues (GIQs) from 2014 to 2022, by technology [116]. This is an indication of the interest in technology development for the next 5 years or so. In 2222, there were 900 GW of solar or hybrid-solar the nation's GIQs, almost 700 GW of storage, and about 300 GW of wind or hybrind wind. However, based on previous history, less than ~25% of this capacity will be built. Fig. R-2 provides GIQ capacity by RTO.

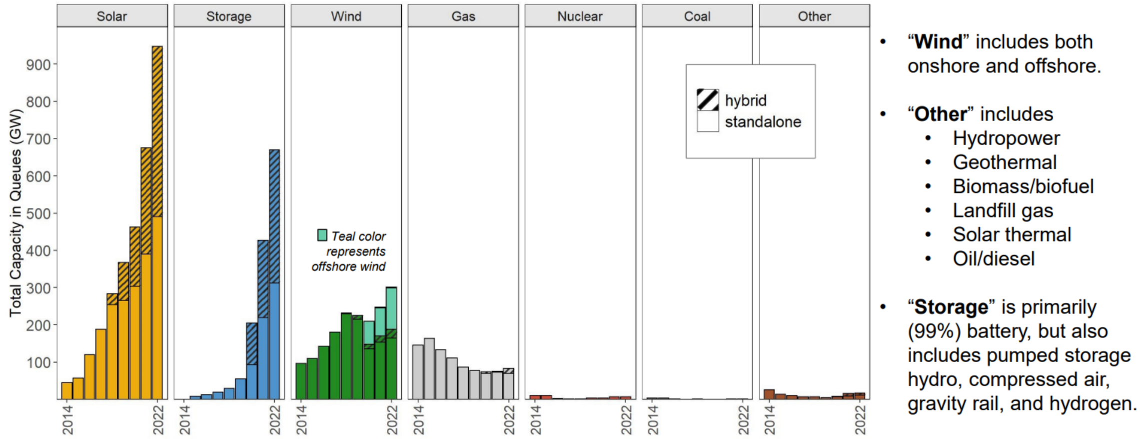


Fig. R-1: GIQ capacity by technology

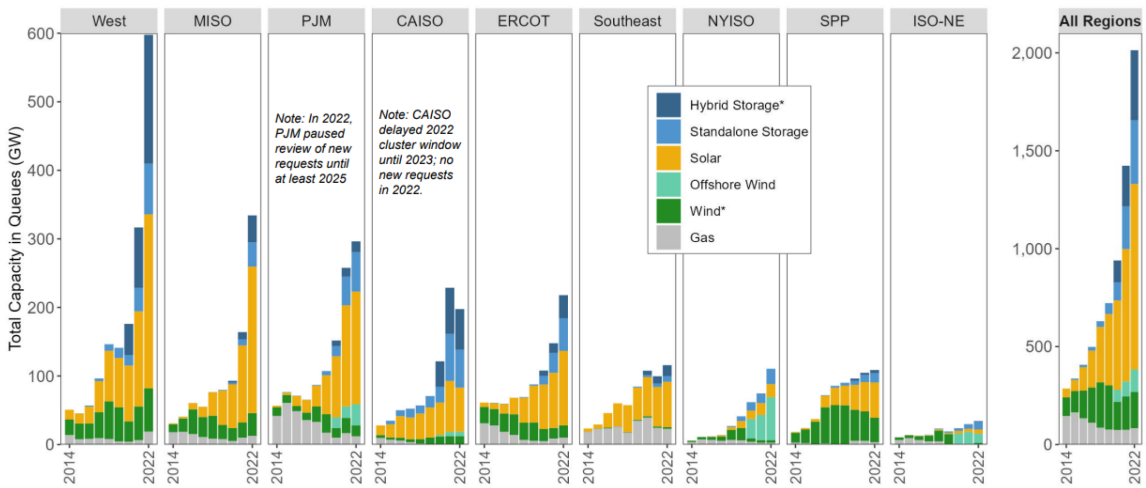


Fig. R-2: GIQ capacity by RTO

It is clear that project backlogs are growing with time, as an increasingly larger number of projects make application for analysis and interconnection. This delays the transformation to a low-carbon grid. Causes of this are summarized in Fig. R-3 [116]; solutions to it are summarized in Fig. R-4 [116].

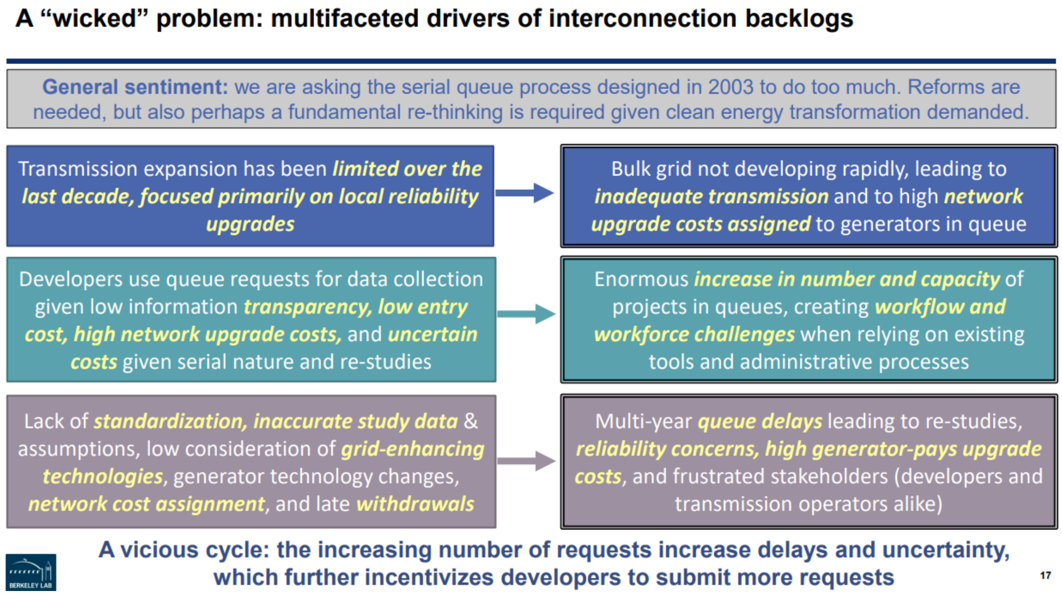


Fig. R-3: Reasons for GIQ backlog

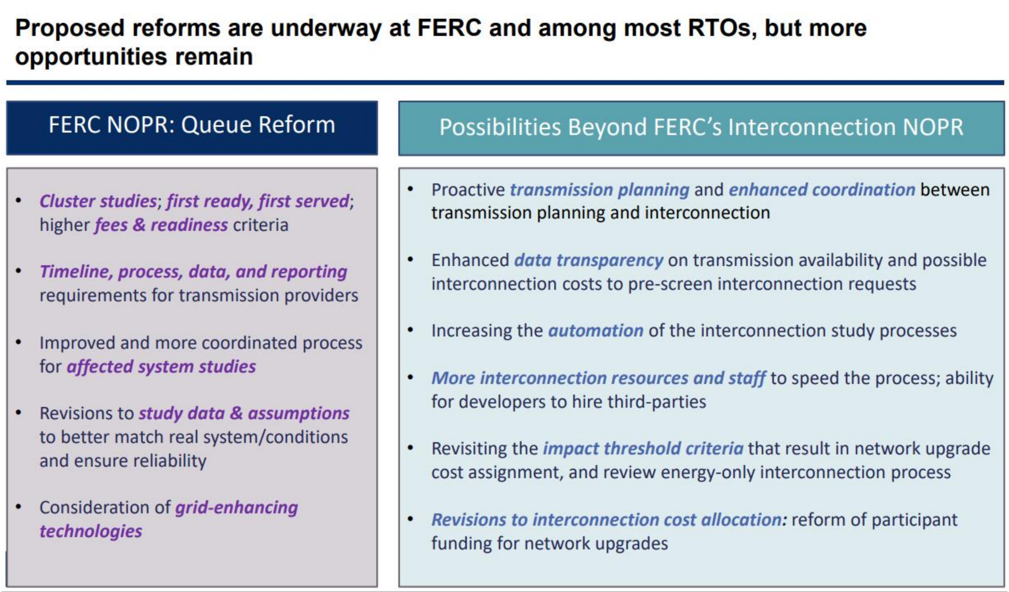


Fig. R-4: Possible ways to address GIQ backlogs

Of the possible ways to address GIQ backlogs, we find the following of particular interest:

1. Transmission development: Increasing transmission availability through expanding the transmission grid would free up capacity to accommodate these projects. There have been and

continue to be efforts at the RTO level to facilitate this (see comments on ERCOT's CREZ projects and MISO's MVP and LRTP projects in Section 10.0). Another approach is to develop high-capacity multiregional transmission, sometimes referred to as a macrogrid. This not only provides the ability to move power at a continental scale, but it also frees up underlying AC transmission and in doing so, facilitates the local capacity needed by these projects.

2. Form clusters: There is need to form coordinating groups (CGs) for the processing of clusters of projects. All projects in a cluster are assessed simultaneously by the CG
3. Increase RTO engineering staff: The analysis work is labor-intensive. It does not seem viable unless there is a sufficient engineering staff to handle it.
4. Automate: Much of the process can be automated and subsequently deployed on the internet. The ultimately goal is that all parties would have access to the deployed tools studies and restudies can be performed and checked by anyone.

APPENDIX – 2000-2010 Nuclear Activities

Introduction

This appendix provides a view of nuclear activities in the US during the 2000-2010 period. There was very positive outlook at that time, as indicated by the information in this appendix. However, expectations were not met, and the expected level of nuclear growth never occurred, for multiple reasons: (1) growth of inexpensive wind and solar technologies; (2) continued safety concerns (e.g., the 2011 Fukushima tsunami-nuclear accident in Japan); (3) the long lead times for constructing nuclear plants; (4) the difficulty of addressing radioactive waste; (5) the high cost and perceived financial risk of lending institutions.

2000-2010 US Nuclear Activities

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 [117] 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 were 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)[8] to build and operate a nuclear power plant. They are:
    - 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 resulted in 24 projected new nuclear plants as of May 2007 as illustrated in Fig. 16a, updated to 23 as of

[8] 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).

January 2009 as illustrated in Fig. 16b, and to 19 as of July 2010 as illustrated in Fig. 16c. The projections are based on submitted combined license (COL) applications.

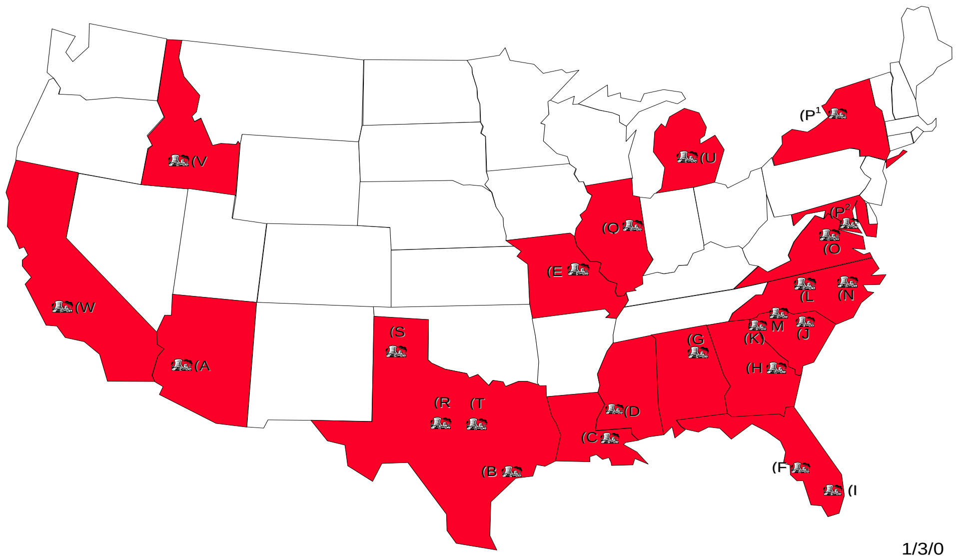


Fig. 16a: Projected nuclear plants as of 5/2007

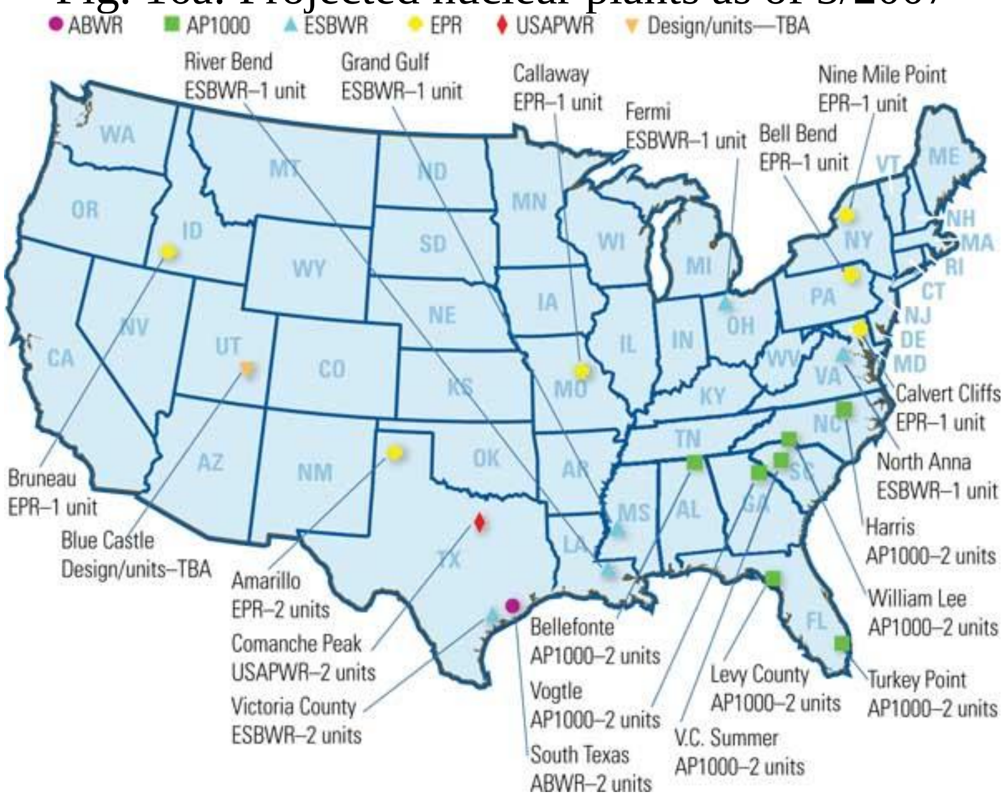


Fig. 16b: Projected nuclear plants as of 1/09

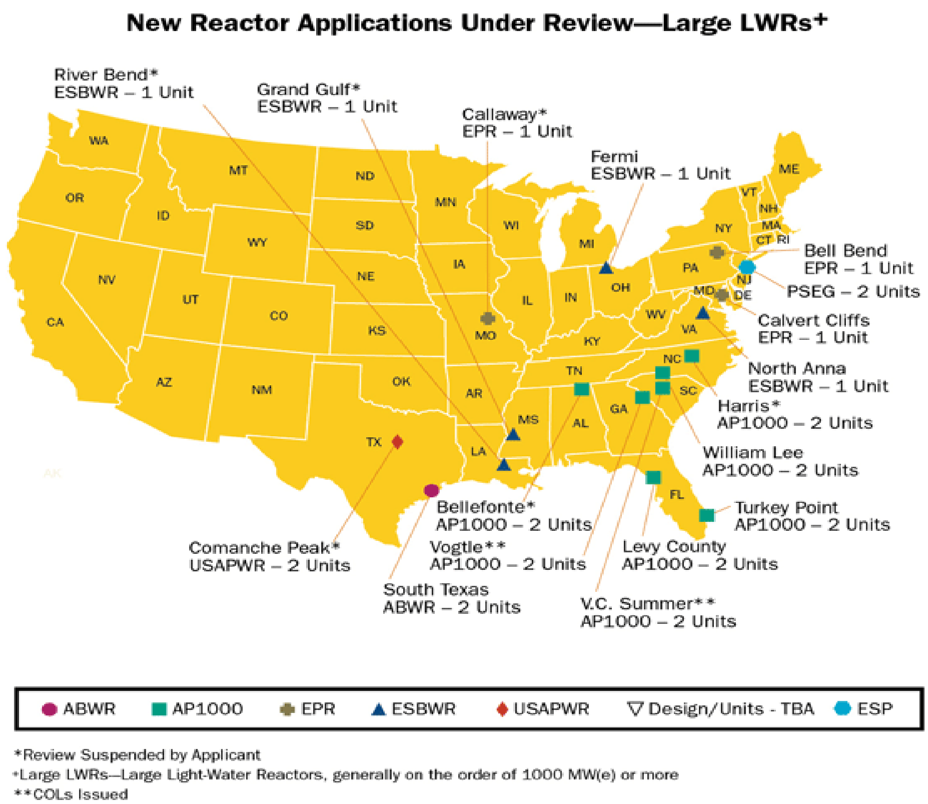


Fig. 16c: Projected nuclear plants as of 7/10

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

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