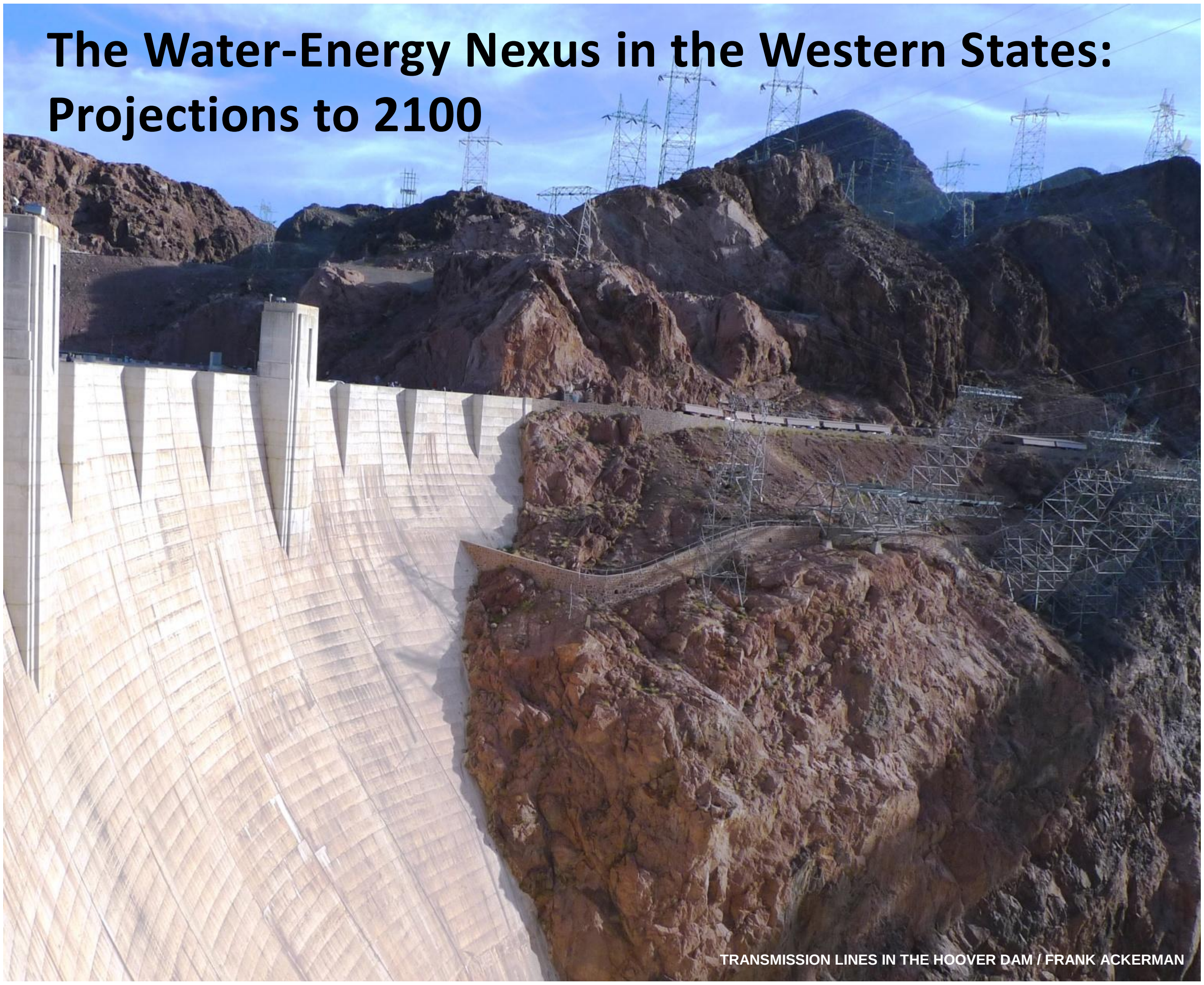
The Water-Energy Nexus in the Western States: Projections to 2100



TRANSMISSION LINES IN THE HOOVER DAM / FRANK ACKERMAN

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Summary

Water and energy are deeply intertwined: production of electricity requires water, and water supply requires electricity. Demand for both is growing, while supply is constrained by limited resource availability, high costs, and the impacts of climate change. These linked problems are sometimes referred to as the "water-energy nexus."

On the energy side, hydroelectric power, which generates almost one-fourth of the electricity used in the western United States, is completely dependent on water flows.[1] Fossil fuel and nuclear power plants, the source of most of the region's electricity, need a constant flow of cooling water in order to regulate their internal temperatures and prevent overheating. The need for cooling water can be reduced, at a cost, by building cooling towers; even more water can be saved, at even greater cost, by switching to a completely closed-loop or "dry cooling" system. A still-experimental new technology, carbon capture and sequestration (CCS), may in the future be able to eliminate greenhouse gas emissions from power plants – but it will also require much more water, raising questions about its feasibility for arid regions such as the Southwest.

On the water side, a lot of energy is needed to deliver water to its users. Nineteen percent of California's electricity is used to provide water-related services, including water supply, wastewater treatment, irrigation, and other uses (Stokes and Horvath 2009). Water from northern California is pumped hundreds of miles, over mountains 2,000 feet high, to reach southern California; the energy used to deliver water to a household in southern California is equal to one-third of the region's average household electricity use (Cohen et al. 2004).

In Arizona, the Central Arizona Project delivers more than 500 billion gallons of water per year through an aqueduct that stretches 336 miles and climbs nearly 3,000 feet from the Colorado River to Phoenix and Tucson (Central Arizona Project 2011). The Central Arizona Project is the largest user of electricity in the state, consuming one-fourth of the output of a major coal plant to push water across the desert and up the mountains.

To examine the water-energy nexus in the Southwest, we modeled long-run scenarios for the region's electricity system. Since state electricity grids are intricately interconnected, we modeled the entire eleven-state Western Electric Coordinating Council, stretching from the Pacific coast through Montana, Wyoming, Colorado, and New Mexico. Our scenarios project power plant construction and operation, focusing on costs, water use, and greenhouse gas emissions, from now through 2100.

In each energy scenario, demand is based on state population trends, and on temperature forecasts from climate scenarios. Supply is initially based on existing power plants, shifting toward a new fuel mix as new plants are built; each scenario uses a different fuel mix, based on political objectives and policy constraints such as water reduction requirements or greenhouse gas emission limits.

[1] In 2009, hydroelectric power provided 23 percent of the electricity generated in the eleven-state Western Electric Coordinating Council; see description in the text, below.

We defined four scenarios: business as usual (BAU); water reduction; carbon cap; and both water and carbon limits. The **BAU** scenario roughly preserves the current percentages of electricity generated from each fuel, though with an increase in the use of wind power. The **water reduction** scenario has a similar mix of fuel types, but moves power plants toward water-conserving technologies – quickly installing cooling towers everywhere, and moving toward dry cooling in mid-century. The **carbon cap** scenario involves a partial shift from coal to nuclear power, combined with slow adoption of CCS technology, reaching 100 percent of coal plants by 2100. The **water and carbon limits** scenario eliminates coal use by 2050 and reduces natural gas use, while rapidly increasing the use of wind, solar power, and other renewables. We examined each scenario both with and without a substantial package of low-cost energy efficiency measures, which reduce the demand for electricity.

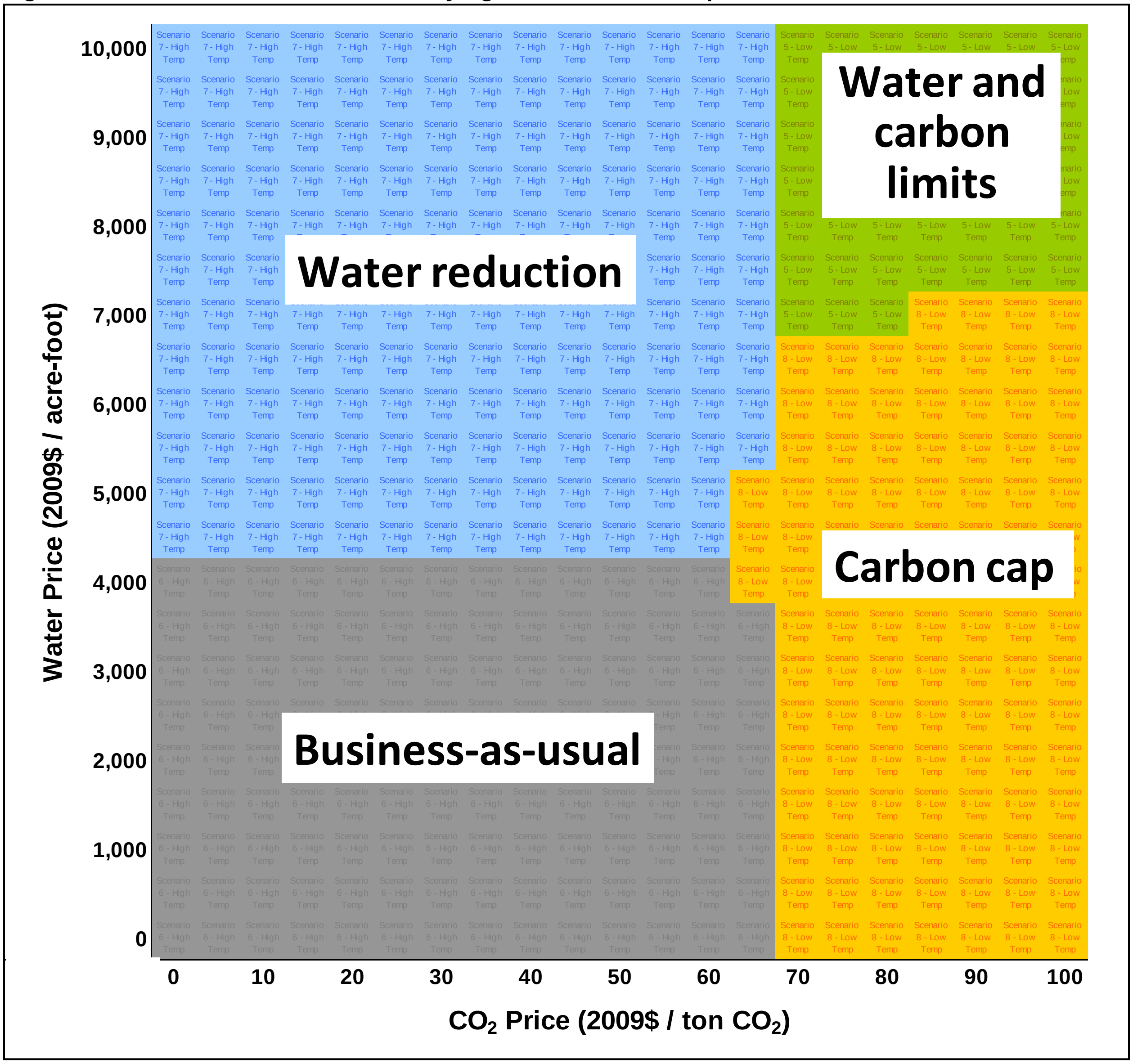
The most surprising conclusion was the relatively small difference between scenarios in total water consumption. The maximum impact, or difference between our most and least water-intensive energy scenarios, was less than 1.2 million acre-feet of water per year by 2100 for the eleven-state region as a whole, concentrated heavily in Arizona (300,000 acre-feet) and California (250,000 acre-feet). For California, this is a fraction of one percent of annual water consumption, much smaller than agricultural and urban water use. For Arizona, it is a larger share of annual water availability, in a state which is one of the most water-stressed; yet even there, the maximum impact of energy choices is only 3 percent of annual water consumption.

Thus the "water-energy nexus" may be a secondary aspect of the problems of water and climate change in the Southwest. Power plants do need water, but their total use is far smaller than agriculture and urban consumption. If water is available for purchase, electric utilities can afford to pay thousands of dollars per acre-foot – orders of magnitude above what farmers are paying – with only minor effects on electric rates. Power plant construction and future generation plans may be limited by absolute lack of water in some regions; they will not be limited by the costs of water, as long as it is available.

The costs of energy supply, as conventionally calculated, do not include any costs for water, or for greenhouse gas emissions. For a closer look at the implications of our energy scenarios, we recalculated their costs, assuming various prices for water and for carbon emissions. These can be thought of as costs which might be imposed on power plants in the future, depending on water and climate policy decisions. Then for each pair of prices – one price for water, and one price for carbon emissions – we asked which scenario would meet the region's energy demand at the lowest cost. The results of this calculation are shown in the figure below.[2]

[2] The figure compares the scenarios with energy efficiency options included, i.e. Scenarios 5, 6, 7, and 8 as defined below.

Figure 1: Least-cost scenarios with varying water and carbon prices



The gray area in the lower-left corner of the figure shows that, if electric utilities have to pay carbon dioxide prices below about $70 per ton and water prices below about $4,000 per acre foot, the business-as-usual strategy has the lowest costs. The blue area in the upper left shows that, at carbon dioxide prices below $70 and water prices above $4,000, the water reduction strategy has the lowest costs. Similarly, at carbon dioxide prices above $70, the carbon cap scenario becomes cheapest; and at carbon dioxide prices above $70 per ton and water prices above $7,000 per acre foot, the water and carbon limits scenario minimizes costs.

In short, a carbon price of $70 per ton of carbon dioxide, which is within the range of current policy discussions, makes the carbon-reducing scenarios lower in cost. While $70 is higher than the prices contemplated in recent Congressional debate, it is lower than the price projected by the Stern Review, or by some European governments. On the other hand, a water price of $4,000 to

$7,000 per acre foot is needed to make the water-conserving scenarios lower in cost. This is well beyond the range of current costs for virtually all water transactions. Foreseeable price incentives could tip the balance toward carbon-reducing scenarios, but are less likely to induce water-conserving options in the electric power industry.

Introduction

Water and energy, two necessities of life, collide in the arid, fast-growing economy of the Southwest. Water is required for the production of electricity, not only for hydroelectric power but also for the vast flows of cooling water needed to keep fossil fuel and nuclear power plants running. How do the choices made in the electricity sector affect the region's use of water? If climate policy or water conservation measures require changes in electricity generation, what alternatives are available, and at what cost?

To address these questions we developed a model of the Western electricity sector, combining the growth of demand with long-term resource choices, technology options, and decisions about the type of future to be pursued. The purpose of this model is to sketch out how electric demand and supply might evolve over a very long planning horizon (to 2100), and what sorts of impacts this evolution might have on electricity cost, carbon dioxide (CO_2) emissions, and water use.

In general, the model estimates demand from 2008 through 2100, driven by population, temperature changes, and assumptions about energy efficiency. The demand is met with resources deployed under any of three fuel mix scenarios – business as usual (BAU), a high-technology carbon-reduction pathway, and a renewable energy-intensive pathway. In turn, each of these scenarios can follow either a BAU water consumption choice, or a water-restricted choice, assuming that water consumption in the electric sector must be reduced. The model estimates required generation, bulk power system costs, CO_2 emissions, and electric-system water consumption.

The model is driven by user-specified choices, not by an optimization procedure, which would attempt to find a least-cost solution. Utilizing a least-cost optimization framework over such a long planning horizon would run the risk of basing long-run resource choices on costs and parameters which are likely to change over the course of the next few decades, if not years. Rather than attempting to specify a policy lever to achieve a particular goal, we structure the analysis to achieve the desired goal and then estimate the cost to achieve that endpoint. This is an exploratory tool, designed to illustrate the tradeoffs between particular resource choices, rather than specifically forecast how a system might evolve.

The model calculates annual values in 2030, 2050, 2075, and 2100. On an ancillary basis we explore seasonal characteristics of the system today and in the future.

Assumptions

The model makes a number of implicit and explicit assumptions about the workings of the electrical system today and in the future. The following are the major classes of assumptions:

- **Region of interest:** Electricity in the West is produced and distributed via a highly interconnected system, and electricity generated for use in California, for instance, cannot be distinguished from generation powering other regions of the West. Therefore, this analysis examines the entire 11-state Western Electric Coordinating Council (WECC), with changes in demand and generation estimated at the state level. The WECC states are Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

- **Per capita demand growth:** Electric consumers in the United States use increasing amounts of electricity each year. Historically, growth due to "electrification" (transitioning from other fuels to electricity) and the electronics age of computers and large-screen televisions have driven increasing use of electricity. However, the rate of this increase has slowed dramatically in recent years, and California has managed to maintain a nearly zero net growth in electricity use per capita over the last three decades. In fact, according to U.S. Department of Energy estimates (EIA 2010b), per capita consumption in the West will fall in the residential and industrial sectors, and grow only moderately in the commercial sector. We assume that increasing interest in basic efficiency (even in the base case) essentially locks per-capita demand in place at 2008 levels. We also assume that the relative fraction of industrial, commercial, and residential use in each state remains at the 2008 level.
- **Population:** We use 2005 U.S. Census forecasts to estimate state-wide population growth in each of the 11 states to 2030, and then maintain the same population growth rate to 2050. After 2050, population is held constant through 2100.
- **Temperature**: Temperature trends for each of the 11 states follow model projections for the B1 (moderate temperature increase) and A2 (a BAU temperature increase) scenarios. Temperature changes relative to a 2008 baseline are tracked on a monthly basis.
- **Response to temperature:** Electrical consumers use increasing amounts of electricity at high and low temperatures to cool and heat spaces, respectively. The shape of this relationship depends on societal norms, building shell efficiency, and HVAC systems (type, fuel, and efficiency), and differs by state. We hold the shape of this relationship constant over time in each state.
- **Electric generating region and transmission constraints:** The location of future generating resources to meet electrical demand will be largely determined by load requirements (the location of the demand), the resources available to meet that demand, and the availability of transmission to move electricity from generation to customers. Rather than attempting to predict the exact location of future generators, we designate fuel mixes for three regions (California, the Northwest, and the Mountain states), and allocate generation among the regions in the same proportions seen today. Therefore, in this analysis, California remains an importing state, the coastal Northwest states stay approximately energy balanced, and the Southwest and Rocky Mountain states remain net exporters.
- **Existing generators:** Generators which are currently in operation are assumed to remain in operation as long as energy from their fuel type is required. Plants which remain online through each of the analysis years (2030, 2050, 2075, and 2100) are assumed to require periodic overhauls, at 50% of the capital cost of building a new generator. This fraction reflects the uncertainty about which generators would need complete replacement over time, and which would simply need incremental upgrades to remain online. Today, there are numerous generators 50 to 60 years old; we assume that such overhauls could be applied to the existing fleet *ad infinitum* to maintain the fleet.
- **Generation technologies**: In the analysis, new generators are built as required to meet load, following the chosen fuel mix. The fuels used are coal, gas, oil, nuclear,

hydroelectric, wind, solar PV, solar thermal, geothermal, and biomass. Operating characteristics for these fuel types, including capacity factor and baseline water use, are fixed at average 2008 values.

- **Carbon capture and sequestration:** In some scenarios, we explore the economic consequences of advancing carbon capture and sequestration (CCS) technology. For those scenarios which utilize CCS, the rate of adoption is fixed: we assume that the technology is still experimental in 2030 and only accounts for 10% of generation. The technology reaches commercial scales later, increasing to 50%, 80% and 100% in 2050, 2075, and 2100, respectively,
- **Generator technology and integration costs:** The cost of generation is determined from the capital, fixed, and variable costs (including fuel) of each type of power plant. Costs for coal, nuclear, and oil generation are derived from AEO 2010; costs for gas, wind, solar photovoltaic, solar thermal, geothermal, and biomass facilities are derived from CEC 2010 assumptions. Costs for carbon capture retrofits and new IGCC plants with CCS are derived from NETL (2007) assumptions. We use a wind integration cost which increases with the fraction of capacity served by wind.
- **Capital recovery factor:** Capital expenditures for new plants and water retrofits are amortized over a 40 year basis at 8.8%, representing a cost of capital which is a rough average of the costs paid by regulated, municipal, and rural cooperative utilities.
- **Hydroelectric availability:** We assume that hydroelectric capacity in the future does not include any additional large dams, and an insignificant number of small hydroelectric facilities; therefore, annual hydroelectric generation is fixed (with the joint assumption that climate change does not vary the precipitation which can be captured by hydroelectric facilities).
- **Water use at existing generators:** The amount of water consumed at existing generators is estimated from EIA data (see below), and assumed to remain as a constant rate unless alternate policies are applied. If, in the model, new standards require lower water consumption, then existing plants which are still in operation are retrofit to meet new standards.

The underlying framework for this analysis is an accounting model with four basic components:

- **Demand:** Demand in the residential, commercial, and industrial sectors in each of the eleven states is a function of population and temperature.
- **Supply:** The supply fuel mix determined by the chosen scenario. This fuel mix, superimposed on the total demand, determines how many generators of each type must be built or retired in each region. The existing fleet provides a basis from which to retire generators, as well as analogues for new fleet additions.
- **Policy:** Various policies may be superimposed on the model, including water reduction requirements and the availability of CCS technology. Carbon and water prices are not modeled as part of this analysis; instead the fuel mix is chosen by the user to reflect carbon requirements. Policies which require reduced water consumption impose retrofits on the fleet, as do CCS retrofit requirements.
- **Output:** The modeled energy output of the system matches energy requirements for the entire WECC system. The capacity required to produce this energy is a function of the resource type, as well as energy penalties imposed by both water and CCS requirements.

> Bulk power costs are based on the continued maintenance of existing resources, wind integration costs, as well as new capital additions, capital costs for water and CCS retrofits, the fuel costs of operating resources, and an estimated cost for energy efficiency programs.

The remainder of this report discusses each of these four components at greater length.

Demand

Consumption and Temperature

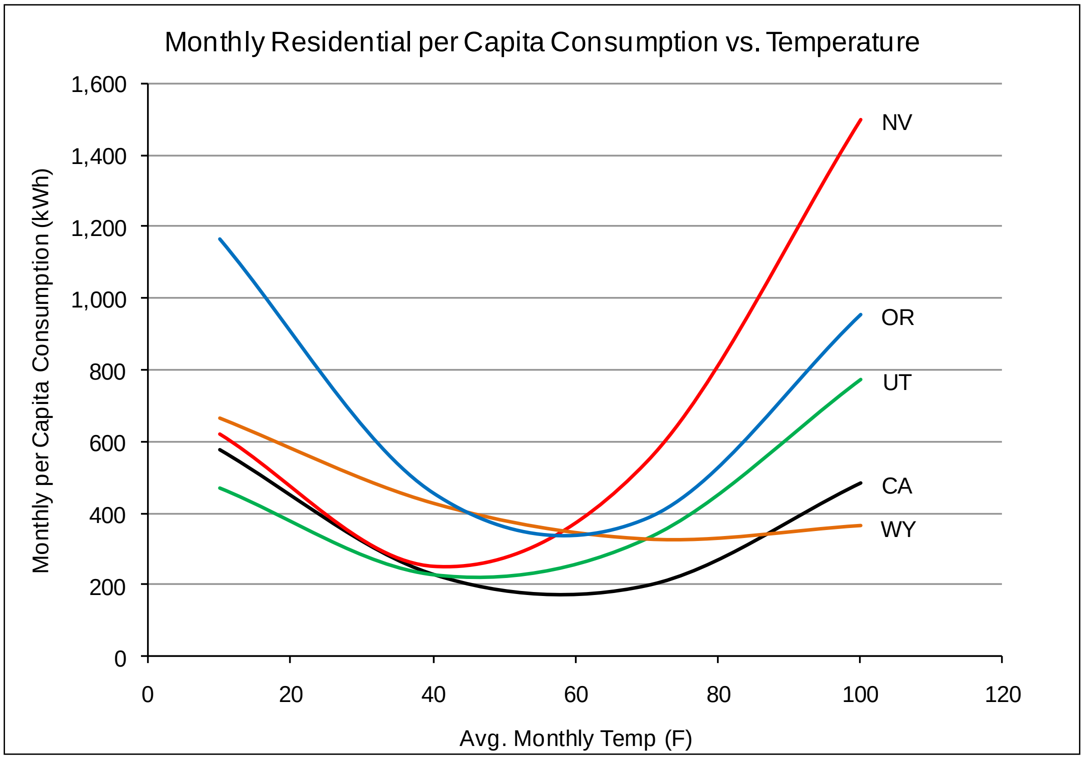
This analysis is designed to estimate changes in energy and water consumption with changes in climate, and is thus driven primarily by population and temperature.

As temperatures rise and fall above and below a comfort threshold, households and businesses use air conditioning and space-heating to maintain comfort. Using monthly consumption estimates for each state (EIA 2010) and population-weighted monthly average temperatures (NCDC 2010) we constructed curves for residential, commercial, and industrial customers in each state for consumption per capita given a particular temperature.

Examples of these curves are given for residential consumers in five states, below, showing significant differences among states. For example:

- In **Oregon** (OR, blue line), consumers use the least electricity at approximately 60 degrees F; use rises at lower temperatures, presumably for heating, and at higher temperatures, for air conditioning. We would anticipate that if climate change drives up temperatures and behavior remains consistent, then Oregonians will use less electricity in the winter and more in the summer months.
- **Californians** use less electricity than Oregonians at every temperature, and their use does not increase as rapidly with high or low temperatures.
- **Nevadans** increase electricity use dramatically at warm temperatures, apparently using increasing amounts of air conditioning as temperatures rise above 50 degrees F.[3] Electric space heating is less common in Nevada, and thus there is less of a change at lower temperatures.

[3] Per capita electricity consumption is based on year-round average population; if there is a seasonal change in population, e.g. more people in Nevada in warm weather, this could also cause a change in electricity use correlated with temperature.



The shape of these curves is based on consumer preference, electric use for air conditioning and space heating, the prevalence of electric intensive or inefficient heating or cooling technologies, and the insulation of homes (and businesses for the commercial sector). These curves may not accurately represent behavior over the long term, but they provide the best available estimate.

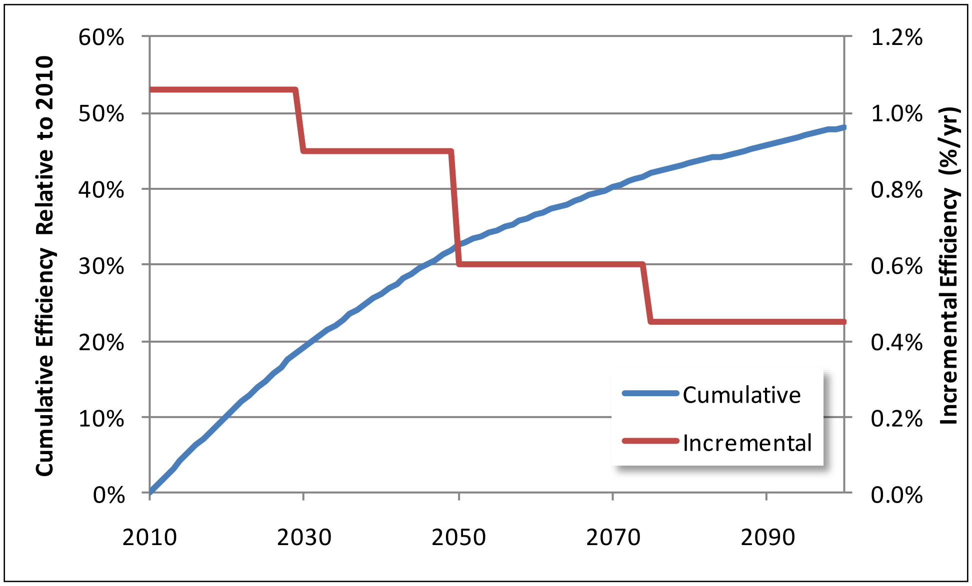
Second-order polynomial (quadratic) curves were fitted to per capita consumption in the residential, commercial, and industrial sectors in all eleven states. From these curves, average monthly consumption per capita is calculated, as well as peak monthly consumption. Aggregate annual consumption for each state, driven by these curves and future temperatures, is multiplied by state population forecasts, according to the U.S. Census (2005).[4] In all scenarios, population is assumed to grow at a steady rate to 2050, and then stabilize.

Efficiency

We make two sets of assumptions about energy efficiency in different scenarios. We assume no underlying per capita load growth in any scenario; that is, our highest energy-use scenarios assume constant per capita electricity use.[5] In other scenarios, we model greater efficiency gains.

[4] This calculation assumes that the commercial and industrial sectors grow at the same rate as population.
[5] There is ample evidence that there is intrinsic load growth within at least the residential sector; many utilities find long-term load growth between 0.5% and 2.5% per year, but it is not clear how long these trends might continue over the long term, or how much of this growth is attributable to electrification vs. population growth. Detailed accounting in California has found a stabilization of load growth (on a per capita basis) from the 1970s. We assume that other states will achieve this stabilization quickly as well.

In the aggressive efficiency scenarios, per capita consumption is reduced by 1.06% annually to 2030, 0.90% through 2050, 0.60% through 2075, and 0.45% through 2100. There is no indication as to how long energy efficiency programs may be effective, or to what extent we can cut long-term consumption; this analysis estimates a 33% reduction in per capita use by 2050 and a reduction of about 50% by 2100 (see figure).



Overall, in the efficiency case, total demand grows 3% by 2030, primarily due to population growth, and then drops 4% below 2010 demand in 2050 and 14% below 2010 by 2100. In contrast, in the non-efficiency (base) case, load grows 30% by 2030 and a total of 42% by 2100. The energy efficiency scenario saves 20% of required demand relative to the base case by 2030, and nearly 40% by 2100.

Supply

In the model, electricity supply is based on an overall fuel mix, defined on a regional basis (for three regions, California, Northwest, and Rocky Mountains / Southwest). In each case, coal, nuclear, oil, wind, solar PV and thermal, geothermal, and biomass fractions are given; absolute capacity and energy availability from hydroelectric facilities are fixed.[6] Gas generation is used to make up any difference in energy requirements.

There are three different fuel mix options:

a) **Business as Usual (BAU):** The BAU case follows AEO 2010 assumptions for meeting supply requirements out through 2035, and then maintains the same percentage of each

[6] While some expansion of small hydroelectric facilities might be possible, their potential contribution is small. There are no active proposals for additional large hydroelectric projects in the contiguous US, and it seems unlikely that any will be built in the foreseeable future.

fuel through 2100. This mix looks largely like today's generation fleet, with a significant increase in wind penetration (to nearly 25% of generation in California by 2030), a moderate increase in coal in the Rocky Mountains and Southwest, and a slight decrease in nuclear energy.

b) **Low Carbon, Renewable Energy Focus:** This pathway is oriented primarily towards replacing coal with renewable energy by 2050. Coal sources are phased out almost immediately in California,[7] and eliminated by 2050 in the rest of the WECC region. Wind penetration reaches 25% in California by 2030, 27% by 2050 in the Northwest, and 20% by 2075 in the Rocky Mountains / Southwest. By 2050, solar PV reaches 10% in California, 4% in the Northwest, and 10% in the Rocky Mountains / Southwest; in the latter region it continues to rise to 23% by 2075. Moderate increases in geothermal (5-10% in all regions) and solar thermal (7% in the Rocky Mountains / Southwest, 3% in California) technologies through 2050 retain a diversity of fuel sources in the West.

c) Low Carbon, High Tech: The high tech pathway assumes that there is a decision to reduce carbon emissions, primarily through the use of carbon capture and sequestration (CCS) on coal units, along with widespread nuclear generation. This scenario maintains BAU fractions of renewable energy. Nuclear generation increases to 20% in the Northwest, 30% in the Rocky Mountains / Southwest, and 32% in California by 2100, replacing gas generation. Coal remains an important part of the fuel mix in the Rocky Mountains / Southwest, but decreases by two-thirds in the Northwest through 2100.

Data

This analysis is based on a database, developed by Synapse Energy Economics, covering the entire WECC region's generating fleet in 2008, comprised of all 3275 generators in the 11 states with at least one megawatt of capacity. These generators include thermal units (coal, gas, oil and nuclear), hydroelectric generators, geothermal projects, as well as large-scale solar installations and wind farms.[8] Data for the location, nameplate capacity, and type of each plant are derived from U.S. Energy Information Administration (EIA) Form 860; generation (and hence capacity factor) are derived from EIA Form 529 for generators and plants; water consumption, where available, is derived from various EIA Forms 923 and 860. We assume that solar PV and wind plants do not consume any water. Plants which do not report water consumption or withdrawals are assumed to use a water rate based on their cooling tower types. Cooling towers types are derived from EIA Form 860.

Cooling structures were classified as either once-through, wet recirculating, or dry:

- **Once-through:** Plants draw water from a source, circulate it through heat exchangers to condense boiler steam, and discharge it back to the same body. The thermal load is transferred into the water, which rises in temperature. These operations typically require

[7] California has a few small coal-fired industrial facilities (primarily refineries) and no large coal-fired electric generators. However, California utilities currently own significant shares in several Southwest coal-fired power plants, and the EIA classifies these as part of the California fuel mix.

[8] Wind turbines are aggregated to the level of farms, or distinct named units comprised of several to hundreds of turbines.

very large volumes of water (thousands to tens of thousands of gallons per MWh), but consume very little of it at the plant itself.

- **Recirculating wet**: Plants draw water from a source, and run the water over exposed heat exchangers with large evaporative surfaces. The latent heat of evaporation provides most of the cooling load. These systems withdraw only 2-5% of the water of a once-through system (200-900 gal/MWh), but all of the withdrawn water is consumed.
- **Dry cooled:** Plants use a large radiating cooling structure to dissipate heat and condense steam. These systems use much less water than a recirculating wet-cooled system (80-90 gal per MWh), but incur an energy penalty in hot weather as heat dissipation becomes less effective.

For the several hundred thermal units which did not report a cooling tower type (either due to size or other exclusions from the environmental dataset), the individual plants were found in Google Earth and a cooling structure visually assessed as either once-through (if a water body, pumping station, discharge stream, and no cooling towers were found), recirculating wet (if a sufficiently sized induced draft or natural draft cooling tower was found on the plant premises), or dry-cooled (if a dry-cooling system rack was seen adjacent to the power plant).

The table below shows water consumption assumptions for plants which do not otherwise report cooling water consumption.

Fuel Type	Prime Mover	Consumption (gal/MWh)	*Notes*
Wet Recirculating			
Coal	ST	480	*3*
Gas	ST	480	*3*
Gas	CC	180	*1*
Biomass	ST	480	*3*
Biomass	CC	180	*4*
Geothermal	ST	1440	*1*
Geothermal	CC	180	*4*
Nuclear	ST	720	*2*
Oil/Other	ST	480	*3*
Oil/Other	CC	180	*4*
Renewable	ST	480	*7*
Solar Thermal	ST	840	*2*
Dry Cooling			
Coal	ST	60	*2*
Gas	ST	60	*2*
Gas	CC	60	*2*
Geothermal	ST	80	*2*
Geothermal	CC	80	*2*
Oil/Other	ST	60	*2*

Fuel Type	Prime Mover	Consumption (gal/MWh)	*Notes*
Hybrid Cooling			
Coal	ST	270	*2*
Gas	CC	120	*2*
Once-Through Cooling			
Coal	ST	300	*2*
Gas	ST	300	*3*
Gas	CC	100	*1*
Biomass	ST	300	*2*
Biomass	CC	100	*2*
Nuclear	ST	400	*2*
Oil/Other	ST	300	*3*
Other			
Gas	GT	0	*5*
Biomass	GT	0	*5*
Hydro		0	
Solar PV		25	*1*
Wind		0	
Waste Heat		0	*5*

Notes: ST = steam turbine; CC = combined cycle; GT = gas turbine. (1) Fisher et al. (2010). *(2) Stillwell et al.*(2009). *(3) Coal-fired equivalent. (4) Gas-fired equivalent. (5) Combustion turbines use negligible water. (6) Unknown. (7) Assumed biomass.*

Combining units which do report water consumption, and units for which we must assume a water consumption rate, we can derive a weighted average for water consumption by fuel type (in gallons/MWh):

Weighted Average Water Consumption	
Coal	558
Gas	287
Oil/Other	162
Nuclear	558
Hydro	0

Weighted Average Water Consumption	
Wind	0
Solar PV	25
Solar Thermal	840
Geothermal	1007
Biomass	383

Retirements and Additions

The model begins with the current composition of generation in the region, i.e. the 3275 existing generators as of 2008; it tracks individual power plants and their generation, fuel use, water consumption, and economic performance over time. The model also allows additional generic resources of each fuel type to be built in each state, in each year of the analysis, as needed to meet demand under the specified scenario assumptions.

Based on the fuel mix, demand, and estimated losses and international imports (equal to the difference between generation and demand in the WECC region in 2008), we estimate required annual generation in each of the analysis years. This generation is distributed:

- over the three sub-regions based on the amount of generation produced in 2008 (assuming the same import/export fractions between the sub-regions),
- into the appropriate resource types based on the scenario assumptions about fuel mix for the analysis year and sub-region, and
- into the 11 states based on the fraction of that fuel type currently located in the state relative to all other states in WECC.

In this way, the fuel mix and generation distribution of 2008 is preserved in the base case, and changes to *either* fuel mix or generation add or subtract incrementally from the amount of each fuel type demanded in each state.

Generation by a specific fuel type in a specific state (i.e. coal in Colorado in 2030) is compared to the amount of generation of that fuel type currently available in the state: if the new amount required exceeds the amount already available, generators in the state are assumed to retire or de-rate. Generators are chosen to retire strictly as a function of age.

As an example, in Colorado, we report 31 current coal generators, delivering 36,400,000 MWh of power to the grid in 2008. If in 2030, the model expects only 33,000,000 MWh of power from coal-fired plants, the model would choose the oldest plants sequentially until 3.5 million MWh were retired. In this case, this reduction would capture 11 plants, all built between 1950 and 1960.

If the amount of new generation demanded from a fuel source exceeds the generation available in a state, generic new resources of the appropriate fuel type are assumed to be built in the state, with capacity factors fixed at current utilization.

Returning to the Colorado example, the state reported twelve wind farms in 2008 with a combined generation of 824,000 MWh. If this generation were to be doubled in the scenario by 2030, the model would assume a new wind farm of 824,000 MWh with a 24% capacity factor (the current average for wind farms), or 390 MW of capacity.

Tracking individual resources allows the model to estimate avoided costs associated with retiring existing resources, as well as the costs of building new resources and the continued capital costs of maintaining existing resources. Due to the length of the analysis period, there are many cases in which the model retires existing facilities in the short term, and then builds new resources in the future. Replacing existing generators with new generators has a distinctly different cost structure than maintaining existing facilities *ad infinitum*, and the model allows for this distinction.

The model also allows for fractions of the fleet to be retrofit for environmental compliance. Currently, a small fraction of the gas fleet in the West is dry-cooled; the model distinguishes these plants from the large, coastal gas-fired power plants with once-through cooling, in terms of retrofit costs. Similarly, as portions of the fleet are retrofit with CCS, the model distinguishes their capital and energy costs and water consumption from portions of the fleet which have not been retrofit. Therefore, maintaining the characteristics of individual fleet elements is a critical component of the model.

Resource Costs

The costs of new resources are fixed at the estimated price of new resources in 2010, according to three public data sources.9 The capacity factors of new plants are also fixed according to the average capacity factor of those resource types in WECC in 2010. Solar PV and solar thermal capacity factors are assumed at 30%. Fuel costs are assumed at rounded values approximating the cost of those fuels in 2008. CO2 emissions rates are assumed at approximate fleet averages.

[9] EIA (2010b); Klein (2010) ; and Geisbrecht (2008).

	Fuel Costs ($/MMBtu)	Total Overnight Cost in 2009 ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW)	Heatrate (btu/kWh)	Data Source	Annualized Capital Value ($/kW-yr)	CO2 Emissions Rate (t/MWh)	Typical Capacity Factor for Units in WECC	Price at Typical Capacity Factor Gen ($/MWh)
Coal	$ 2.00	$ 2,078	$ 4.69	$ 28.15	9,200	AEO 2010	$ 182.97	1.10	73%	$ 56.03
Gas (Adv CC)	$ 8.00	$ 990	$ 2.69	$ 7.17	6,470	CEC 2010	$ 87.15	0.60	28%	$ 92.48
Oil/Other	$ 20.00	$ 984	$ 2.11	$ 12.76	7,196	AEO 2010	$ 86.60	0.80	22%	$ 197.63
Nuclear	$ 1.70	$ 3,820	$ 0.51	$ 92.04	10,488	AEO 2010	$ 336.31		81%	$ 78.85
Wind		$ 1,990	$ 5.50	$ 13.70		CEC 2010	$ 175.19		24%	$ 97.22
Solar PV		$ 4,550	$ -	$ 68.00		CEC 2010	$ 400.55		30%	$ 178.29
Solar Thermal		$ 3,687	$ -	$ 68.00		CEC 2010	$ 324.58		30%	$ 149.38
Geothermal (Binary)		$ 4,046	$ 4.55	$ 47.44		CEC 2010	$ 356.18		51%	$ 94.93
Biomass IGCC	$ 2.00	$ 2,997	$ 4.00	$ 150.00	10,500	CEC 2010	$ 263.84	0.40	46%	$ 128.25
Existing Coal with CCS	$ 2.00	$ 4,402	$ 11.14	$ 41.22	12,534	NETL 2008	$ 387.54	0.11	73%	$ 103.11
IGCC with CCS	$ 2.00	$ 3,776	$ 4.54	$ 47.15	10,781	NETL 2008	$ 332.43	0.11	73%	$ 85.33

It should be noted that these costs are necessarily only rough approximations for the purposes of a century-long analysis. In today's market, nuclear power stations have been very difficult to site, and typically far more expensive than listed here. However, the industry asserts that if a market is re-created, the price could fall towards a baseline level shown here. Similarly, the price of carbon capture and sequestration is highly speculative, as there are *no* commercial demonstrations of this technology. Very few new coal plants have been built in the last few years, and those which have been completed have far exceeded the costs shown here. However, again we assume that over the long term, price spikes might potentially be dampened.

In the same vein, there is ample evidence that the price of solar PV is falling very quickly, and some industry experts assert that the price could fall by another 50% in the next twenty years due to a rapidly expanding market and industry efficiency. However, this analysis chooses to simplify the problem and fixes prices according to national estimates. These prices are generally considered to be conservative (i.e. low for fossil and nuclear technologies and high for renewable energies).

- **Wind** is a highly intermittent resource, and at increasing penetrations, it requires backup generation and robust grid technologies to ensure a stable voltage and energy supply. The costs of wind integration rise as the fraction of capacity served by wind energy increases. This analysis assumes a cost of 0.313 $/MWh per percentage of capacity served; at 20% wind penetration, this would add $6/MWh to the cost of wind power.
- **Carbon Capture and Sequestration** exacts an energy penalty on plants with post-combustion capture. We estimate a 35% energy de-rate for CCS.[10]

[10] Carbon Capture Journal (2009); Specker et al. (2009).

- **Energy efficiency** is a highly cost effective mechanism for reducing energy demand; we assume an all-in cost of 4.5c/kWh for energy efficiency, a conservative value close to the upper (more expensive) end of what utilities are able to achieve today.

Capital costs and maintenance of existing resources

All costs are reported and calculated in constant 2009 dollars. We assume that new energy resources recover their capital costs over a 30 year time-period with a capital recovery factor of 8.8%. Similarly, new environmental upgrades (e.g. new cooling infrastructure) are also amortized at an 8.8% rate.

We assume that all resources require significant periodic maintenance. The degree to which this maintenance needs to be performed is uncertain, although recent research at Synapse Energy Economics suggests that even the oldest units in the existing coal fleet still have approximately 50% of their debt unrecovered due to continuous upgrades and major repairs. Therefore, we assume that at any given time, approximately 50% of the capital expenditures for plants which have survived since the last analysis period are unrecovered. This capital expenditure, even after a plant should have fully depreciated, represents incremental upgrades to keep the plant operational, and eventually leads to much of the plant being rebuilt over time.

Policy

Low-Carbon Future

The model is designed to allow the user to construct a variety of low-carbon futures, through the implementation of renewable energy, or CCS and nuclear power, or demand reduction through efficiency, or a combination of the above. Each of these choices has repercussions for water consumption and the price of the electricity system as a whole, as well as for the generation mix in each state. Low carbon futures are achieved by choosing an appropriate fuel mix, demand basis, and choosing whether CCS is an available option.

Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is modeled by choosing the fraction of coal plants which are equipped with CCS in each analysis year. We assume that if CCS is implemented, it will be in a demonstration phase through 2030, and then be adopted more rapidly through the middle of the century. We define the CCS trajectory over time as follows:

Carbon Capture and Sequestration Availability					
	2009	2030	2050	2075	2100
CCS Penetration	0%	10%	50%	80%	100%

We assume that the most recently built coal plants (which are likely to be the most efficient and last to retire) would be the most likely candidates for CCS. Plants are ranked by age through the entire region, and the appropriate fraction of the existing fleet, starting with the newest plants, is selected for retrofit. Existing coal plants which are retrofit for CCS have an additional cost for the retrofit, and a new levelized cost of power thereafter. New coal plants which are built as CCS are assumed to be built as IGCC and have a different levelized cost of energy. Once a plant is equipped with CCS, it retains it throughout the later years of the analysis.

We assume that CCS technology reduces output by 35% (see cost assumptions, above), thus effectively requiring additional new generation to come online to meet demand; we also assume that a CCS plant uses 80% more water than a traditional coal-fired power plant.

We do not model CCS for gas-fired plants.

Low Water Future ("High Efficiency Water Use")

The model allows a water use scenario for the electric sector to be selected by setting two criteria: (a) a water consumption standard in any given analysis year, for specific fuel types of plants, and (b) a choice whether or not such a water standard applies to plants already existing at that time; that is, a choice whether or not plant water consumption is grandfathered. These assumptions determine whether, and how rapidly, plants implement retrofits for cooling structures. It is assumed that these policies apply across all states in the region.

Water Consumption and Retrofits

There are large-scale, commercially available technologies for reducing water consumption at power plants. For a plant currently equipped with a once-through cooling system, if there is sufficient property available and the configuration of the plant is favorable, a wet cooling tower can be installed for a capital cost averaging approximately $175/kW of capacity. At plants which are already equipped with a wet cooling tower, the cost of upgrading to a dry cooling structure is 3-7 times higher than building a wet cooling tower, and will impose a 2% energy penalty on the system.

Implementing the water consumption standard in the model forces all new plants of each fuel type to use a particular cooling technology in a given year. These assumptions are given in the tables below. When this option is turned on, plants which have a higher water consumption rate than the standard are assumed to retrofit to the standard. These plants have a capital expenditure starting in the year that the standard is implemented, amortized at the same 8.8% capital recovery factor as other investments in the model.

If the grandfathering option is turned off, then all existing plants also install the specified cooling technology. Environmental upgrades are much more expensive to retrofit than to build as part of the original plant construction. The capital costs for retrofits are shown below.

The table below shows the assumption for water consumption retrofits in the low water future:

Water Infrastructure Assumptions (Cooling Type)	2030	2050	2075	2100
Coal	RCRC	DRY	DRY	DRY
Gas	RCRC	DRY	DRY	DRY
Oil/Other	RCRC	DRY	DRY	DRY
Nuclear	RCRC	HYB	HYB	HYB
Solar Thermal	RCRC	DRY	DRY	DRY
Geothermal	RCRC	DRY	DRY	DRY
Biomass	RCRC	DRY	DRY	DRY
Coal with CCS	RCRC	DRY	DRY	DRY

Water Consumption Assumptions (Gallons per MWh)	2030	2050	2075	2100
Coal	558	60	60	60
Gas	120	60	60	60
Oil/Other	162	60	60	60
Nuclear	558	309	309	309
Solar Thermal	840	80	80	80
Geothermal	1,007	80	80	80
Biomass	383	60	60	60
Coal with CCS	1,004	108	108	108

Notes: RCRC = recirculating (wet) cooling; DRY = dry cooling; HYB = hybrid wet/dry cooling (because some wet cooling is required for safety at nuclear plants)

The table below shows the cost assumptions to build a plant with a cooling structure of a given type. The left-hand table shows the costs of recirculating (wet) or dry cooling when built as part of a new plant, and the right-hand table shows the costs to retrofit an existing plant from once-through cooling to recirculating cooling, or from recirculating cooling to dry cooling.

Capital Costs of Water Controls ($/kW)	RCRC	DRY
Coal	$60	$170
Gas	$20	$60
Oil/Other	$60	$170
Nuclear	$40	$80
Solar Thermal	$90	$280
Geothermal	$60	$170
Biomass	$60	$170

Capital Costs of Water Upgrades ($/kW)	RCRC	DRY
Coal	$230	$890
Gas	$100	$300
Oil/Other	$100	$300
Nuclear	$310	$930
Solar Thermal	$345	$1,035
Geothermal	$230	$690
Biomass	$230	$690

Assumptions for costs are taken from specific cases over the last decade where plants have either actively retrofit, or scoped out retrofit plans. While there are very few examples to date of plants which have undergone significant retrofits to reduce water consumption, there is now significant interest in this area due to the potential impact of EPA rules implementing Section 316(b) of the Clean Water Act; that section caps the water withdrawal rate by power plants, effectively prohibiting once-through cooling.

Sources for cost and water consumption information include studies for the CEC on retrofitting coastal California steam plants with once-through cooling (Tetra Tech Inc. 2008), the Electric Power Research Institute (EPRI 2007), EPA documents, workshop materials and testimony (Maulbetsch and Zammit 2003; Powers 2003 and U.S. EPA 316(b) Phase II Technical Development Document, Chapter 4, as cited in Powers 2003; EPA 2001; Bamberger and

Allemann 1982), white papers, and other documents (Zhai and Rubin 2010; Shenoy, Gupta, et al. 2006; Kosten and Wyndrum 1994; Kelly 2006).[11]

Scenario Narratives

The analysis follows five core scenarios, and three sensitivities. The core scenarios can be considered the extremes on a multi-dimensional matrix. The first dimension represents societal interest in reducing water consumption, and the second dimension represents concern about greenhouse gas (carbon dioxide) emissions. The first four scenarios all present technical methodologies to address these concerns through retrofits and high tech solutions. The fifth scenario (in effect, representing a third dimension) is a method of addressing the concerns through more aggressive energy efficiency and a deep penetration of renewable energy. Scenarios 6 through 8 are sensitivity analyses which combine the other scenarios with aggressive energy efficiency.

The matrix of scenarios looks like the following:

	Baseline efficiency		**Increased energy efficiency**	
	Water Insensitive	**Water Sensitive**	**Water Insensitive**	**Water Sensitive**
CO_2 Insensitive	**Scenario 1** BAU	**Scenario 2** Water matters, retrofits	**Scenario 6** BAU, with energy efficiency	**Scenario 7** Water matters, retrofits & energy efficiency
CO_2 Sensitive	**Scenario 3** Carbon matters, CCS and nuclear energy	**Scenario 4** Carbon and water matter, high tech pathway	**Scenario 8** Carbon matters, CCS and nuclear energy, and energy efficiency	**Scenario 5** Carbon and water matter, efficiency and renewable energy

Scenario 1: Business as Usual

Western states take no specific action to reduce emissions of greenhouse gasses in the electric sector. Temperatures rise along the A2 climate pathway, driving a moderate increase in consumption.

With growing demand, CO_2 emissions from Western states grow 34% by 2050.

[11] Also, El Segundo Power Plant Project EIS, Chapter 4: http://www.energy.ca.gov/sitingcases/elsegundo/documents/applicants_files/afc_cd-rom/VOLUME%201A/Section%204.pdf

Coal, gas, and hydroelectric generation remain the primary fuel types through the end of the century, although wind generation picks up an additional 9% of the electric sector by 2050. Overall, non-hydroelectric renewable energy rises from 5% to 15% of generation.

The electric sector makes no specific move to reduce water consumption. Freshwater consumption by electric generators rises by 35%.

Scenario 2: Water Matters – Retrofit Pathway

Western states take no specific action to reduce emissions of greenhouse gasses in the electric sector. Demand, CO_2, fuel mix, and climate consequences are nearly identical to Scenario 1. With increasingly short water supplies in the West, the electric sector is mandated to meet Best Available Retrofit Technology standards, and steam units are phased towards dry cooling. To comply with Section 316(b) of the Clean Water Act, all remaining once-through cooling units are retrofit with wet cooling towers by 2030.

Half the coal (as well as biomass) fleet is retrofit for dry cooling by 2050, and the whole fleet is equipped for dry cooling by 2075. Half the gas fleet is retrofit for dry cooling by 2030, and the remainder is retrofit by 2050. Finally, it is assumed that the nuclear fleet must maintain some amount of wet cooling to meet safety standards, therefore the fleet moves to hybrid operations by 2050. By 2050, water consumption drops by 50%.

Scenario 3: Carbon Matters – High-Tech Pathway

Western states (and the United States) take steps to reduce carbon emissions through CCS technology in the coal fleet, and increased reliance on nuclear power. CO_2 emissions fall to 43% of the 2009 level by 2100. Coal shrinks slightly to 27% of generation in the West (from 32%), while nuclear power nearly doubles from 8% to 14%. CCS technology slowly permeates the coal fleet, reaching 65% penetration by 2050 and 100% by 2100.

Action taken to curb greenhouse gas emissions leaves temperatures at the B1 climate pathway. However, the electric sector makes no specific move to reduce water consumption. Indeed, water consumption from CCS and new nuclear plants drives up water consumption by 40% by 2050 and over 50% by 2100.

Scenario 4: Carbon and Water Matter – High Tech Retrofits

Western states pursue carbon reductions and water use reductions through incremental improvements in the existing fleet, and future capacity additions along a high-tech pathway. The generating fleet, consumption, CO_2, and temperature consequences are similar to Scenario 3.

Increasingly tight water supplies cause regulators to compel reduced water use in steam generators. With retrofit requirements as in Scenario 2, water consumption drops markedly.

Because of the higher water consumption requirements of CCS technology, and a small but important energy penalty exacted by dry cooling in warm climates, CO_2 emissions do not fall quite as low as in Scenario 3 (to 44%, rather than 43%) and water use does not fall as much as in Scenario 2 (drops by 37% rather than 43%).

Scenario 5: Carbon and Water Matter – Efficiency and Renewable Energy

Western states drive towards carbon reductions and water use reductions through a comprehensive energy system redesign, including:

- Reducing energy consumption in 2030 to 2009 levels (despite population growth), and cutting consumption 32% below that level by 2100.
- Retiring all existing coal plants by 2050 (and building no new coal plants).
- Cutting natural gas consumption in half between 2050 and 2100.
- Increasing wind energy to over 20% of generation by 2050, and non-hydroelectric renewable energy (including solar thermal and photovoltaics) to 46% of generation by 2100.
- Retrofitting remaining gas, nuclear, solar thermal, biomass, and geothermal units for dry-cooling along a Scenario 2 path.

The result is that most carbon emissions and water use are eliminated: Carbon emissions are reduced to 29% of 2009 emissions by 2050, and to less than 9% by 2100; water consumption in the electric sector is reduced by 76% by 2050.

Scenario 6: Business as Usual – Energy Efficient Economy

Western states take no specific action to reduce emissions of greenhouse gasses or water in the electric sector. However, effective mechanisms are found to implement widespread efficiency programs, and energy efficient technology increasingly dominates the housing, consumer goods, and industrial sectors. The fuel composition of the electric sector does not substantively change, following fuel mix assumptions in Scenario 1.
In this scenario, demand is stable through 2030 and falls by 26% by 2100.
Carbon emissions fall 18% by 2050 and 40% by 2100, but this is insufficient to prevent climate change. The climate shifts along the A2 pathway.
The electric sector makes no specific move to reduce water consumption. However, due to demand reductions, freshwater consumption by electric generators in the West drops by 14% by 2050 and nearly 40% by 2100.

Scenario 7: Water Matters – Efficiency and Water Retrofits

Western states take no specific action to reduce emissions of greenhouse gasses in the electric sector. However, efficiency measures are implemented, driving demand, CO_2, fuel mix and climate consequences identical to Scenario 6.

With increasingly short water supplies in the West, the shrinking electric sector is mandated to meet Best Available Retrofit Technology standards, and steam units are phased towards dry cooling, following a retrofit schedule identical to Scenario 3.

Water consumption by the electric sector drops by 63% by 2050, and 88% by 2100.

Scenario 8: Carbon Matters – High Tech Pathway

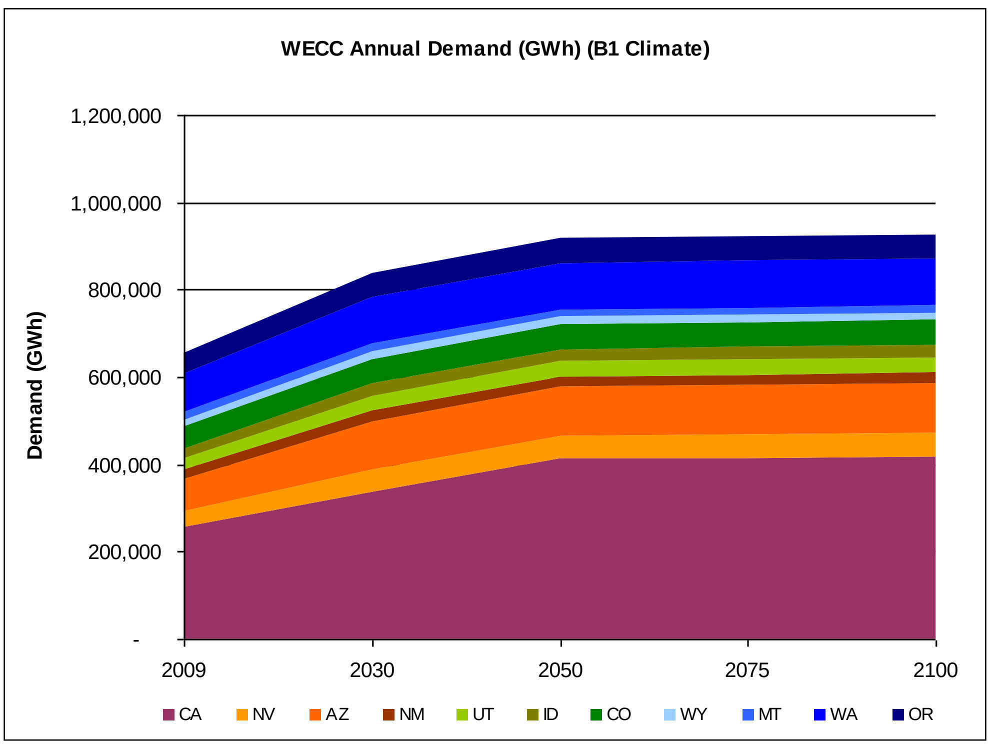
Western states (and the US) take steps to reduce carbon emissions through efficiency gains, carbon capture and sequestration technology in the coal fleet, and increased reliance on nuclear power. The fuel mix for this scenario looks like Scenario 3.

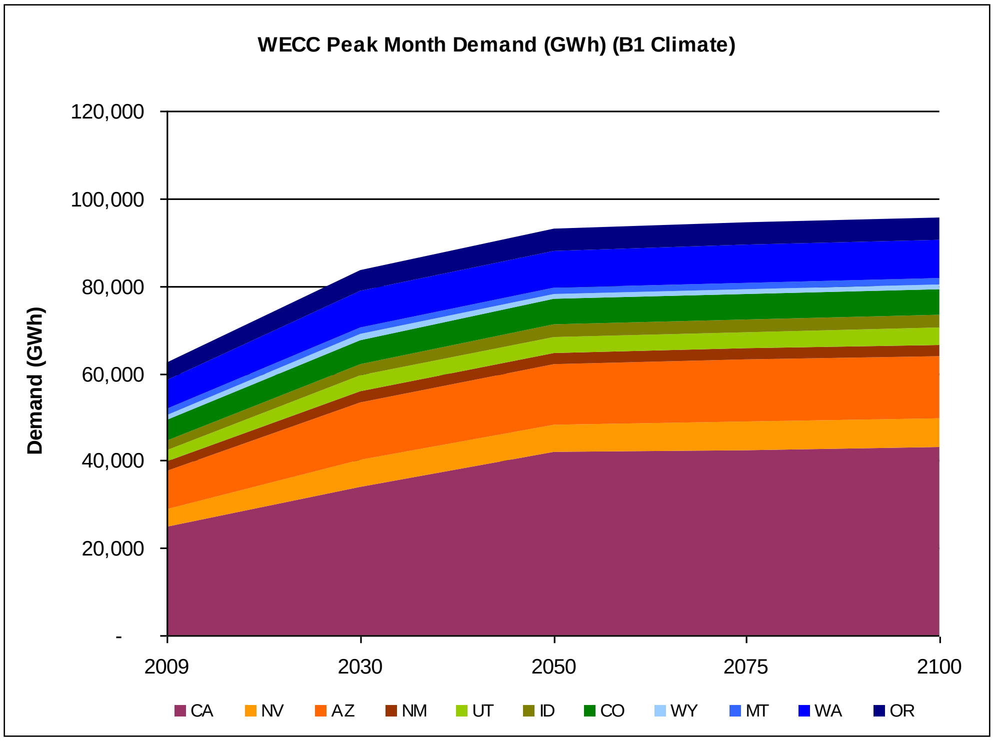
Carbon emissions fall by 56% by 2050 and 91% by 2100. The climate maintains the B1 pathway. Due to the demand reduction, water consumption falls by 11% by 2050 and 33% by 2100.

Results

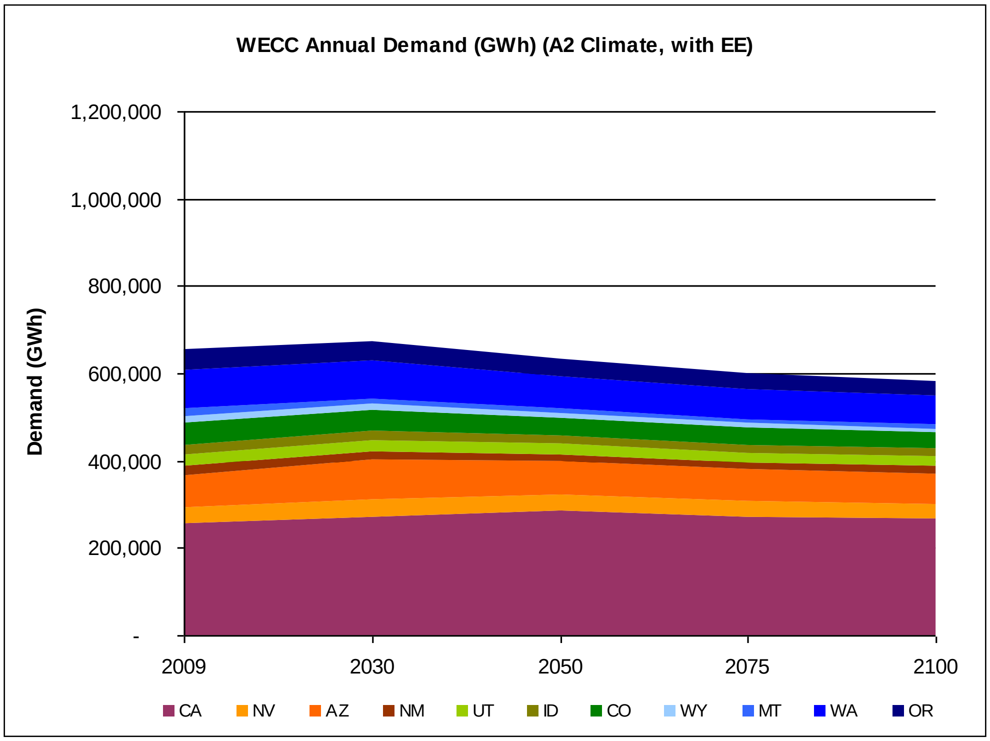
Demand

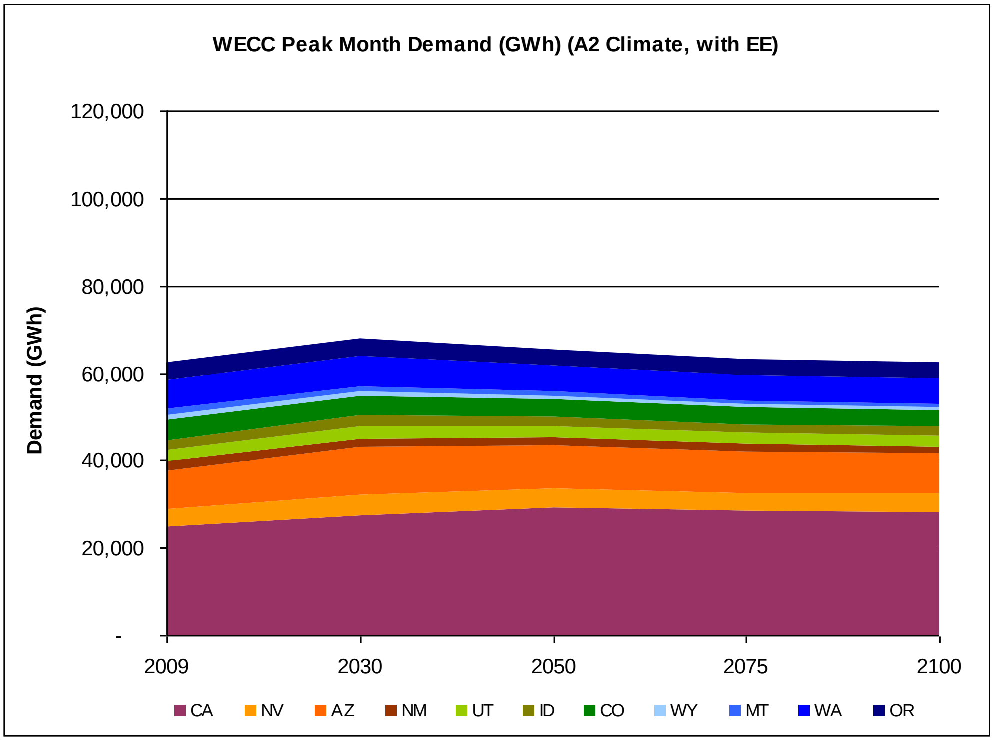
In the B1 climate scenario, in the absence of additional efficiency changes, population change in the West drives increasing annual consumption through 2100, from around 650 TWh today to 930 TWh per year in 2100 (see figure, below). Absolute non-coincident month peak rises from 63 GWh to 96 GWh over this same time period.



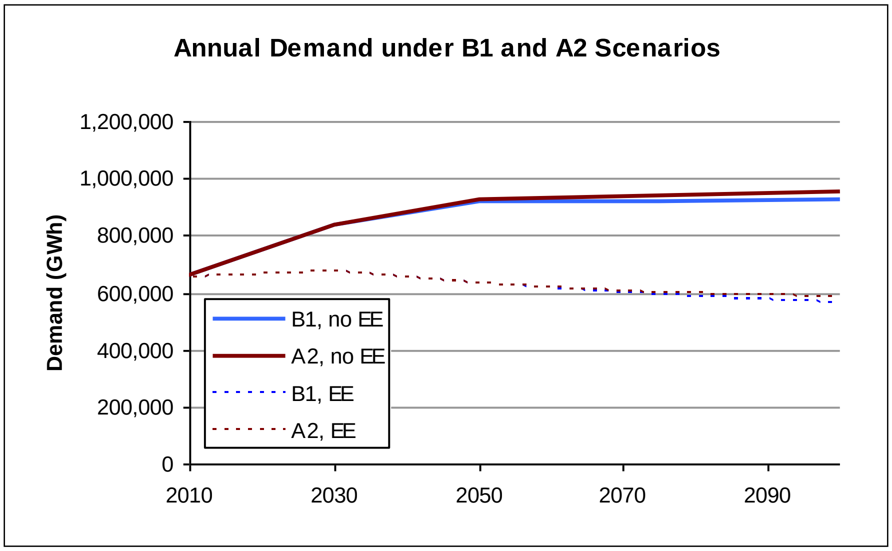


Under the efficiency assumptions, demand stabilizes to 2030, and falls moderately through 2100, as shown in the figures below.

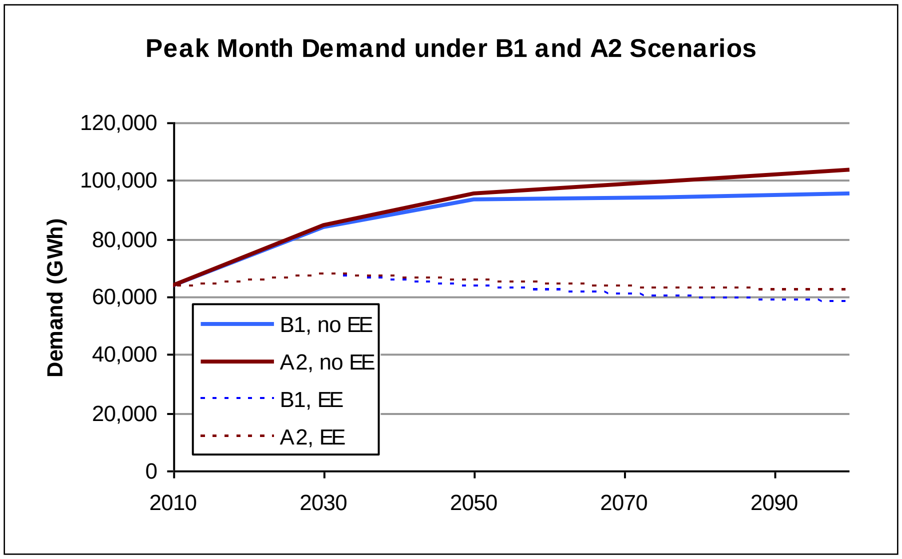




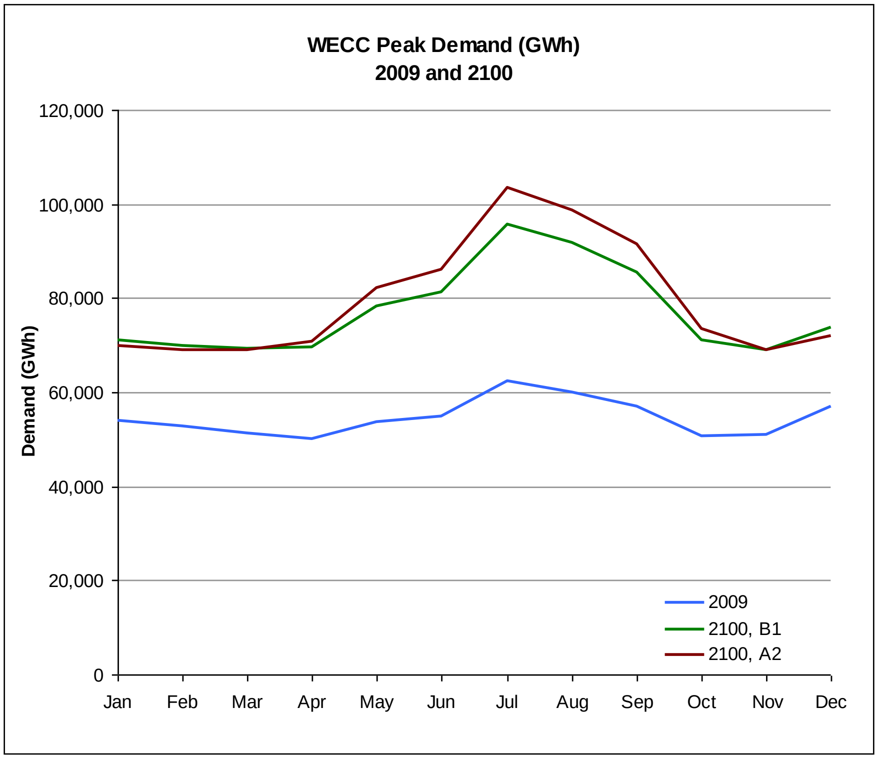
Under climate change, demand rises moderately, but due to the moderate use of air conditioning today throughout the West, and particularly the efficient use of air conditioning in California,[12] there is little difference in annual consumption due to climate change. The figures below show the difference between the B1 and A2 scenarios for total and peak month demand in the baseline and increased energy efficiency (EE) scenarios.



[12] More precisely speaking, California's electricity use shows little response to temperature changes; this suggests very efficient use of air conditioning.

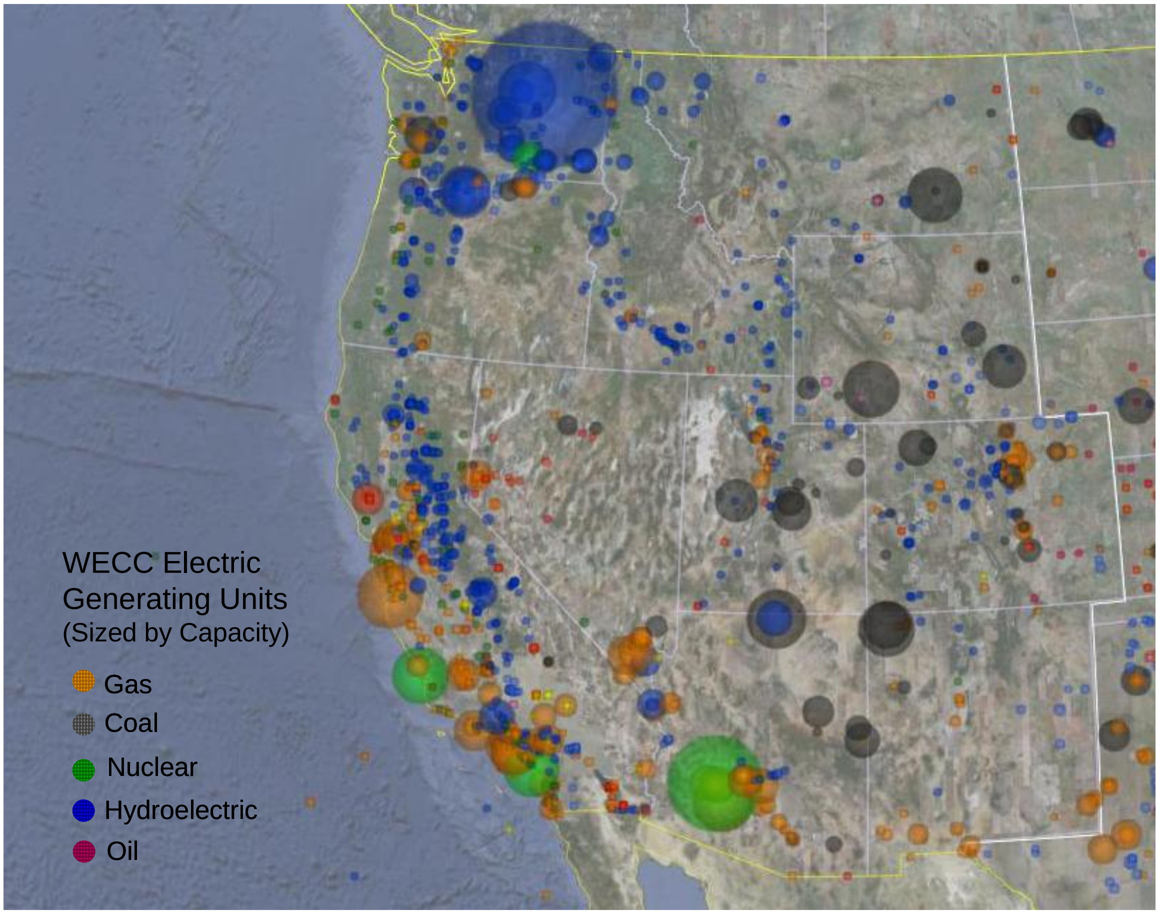


A limitation of our model appears in the treatment of the annual load curve; much of the increase in annual demand occurs in or near the peak months (see figure below). This increase in peak demand would, in reality, require additional capacity to deal with the hottest days – implying a reduction in overall capacity factor. The model used here is not able to adjust capacity independently of generation.

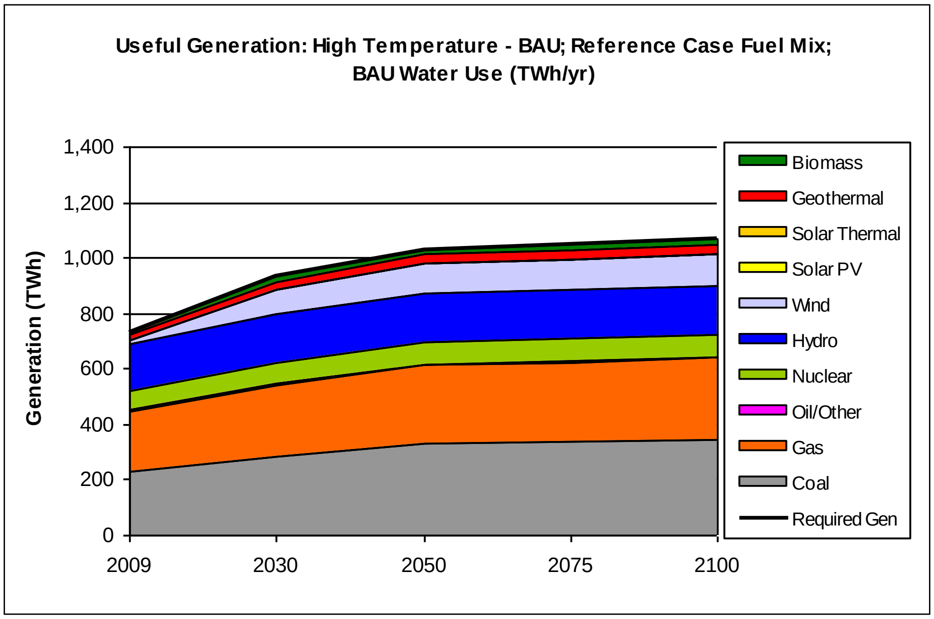


Supply

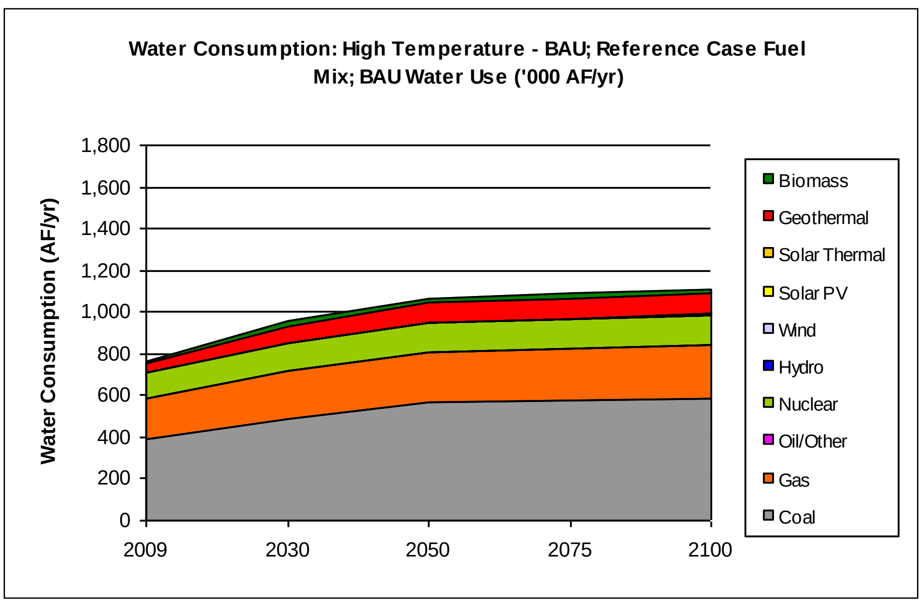
The model begins with the 3275 existing generators throughout the 11 Western states. The map below shows the locations of those generators, colored by type and sized by capacity. There is a minimum size threshold on the map, implying that the smallest generators are not to scale; many small hydroelectric facilities would not show up without this threshold. The largest station, Grand Coulee Dam, is 6,810 MW, while Palo Verde (the green circle in Arizona) is 4,200 MW. For comparison, many of the small hydroelectric generators are less than 5 MW each.



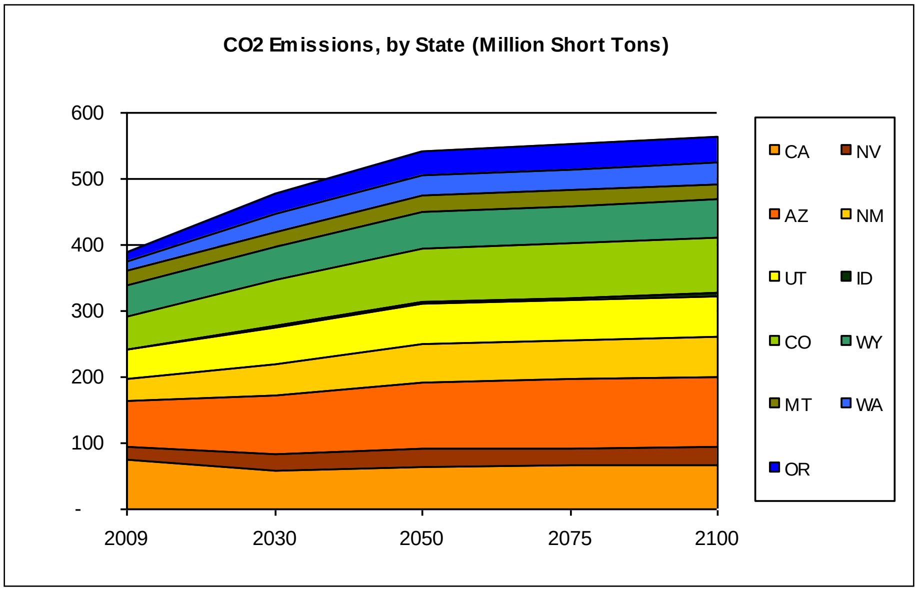
In the reference baseline (BAU, Scenario 1), the generation mix looks much like today with additional wind generation added through 2050. After 2050, the fuel mix does not change substantially (see figure below).



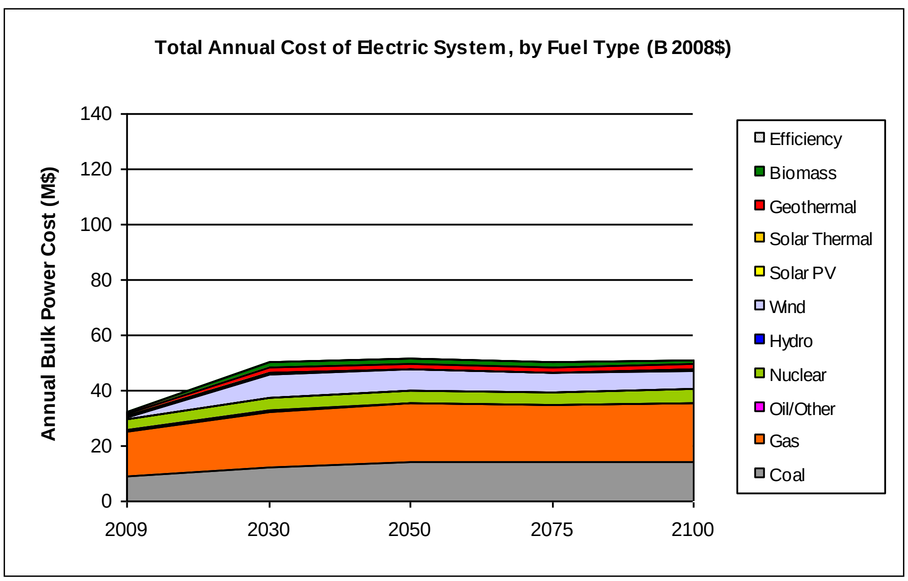
Water consumption is a function only of steam generation, and with no additional retrofits, the system increases water consumption in pace with fossil generation.



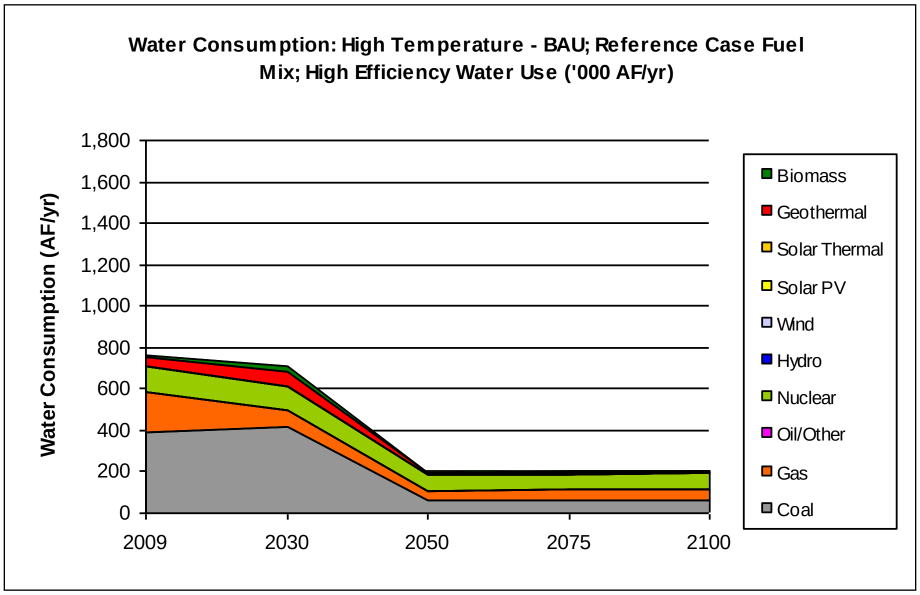
CO_2 emissions in Scenario 1 rise by 40% by 2050…



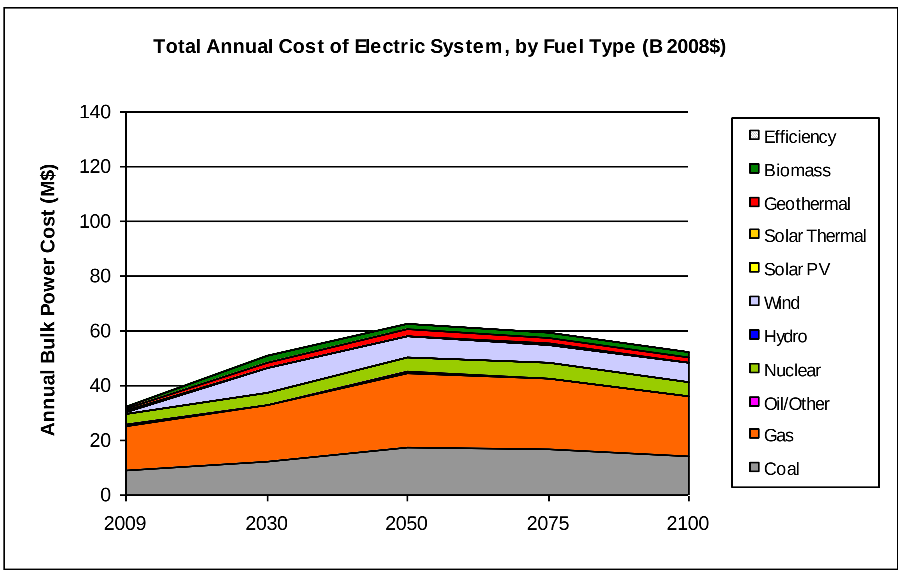
… but the cost of the system is fairly stable over time:



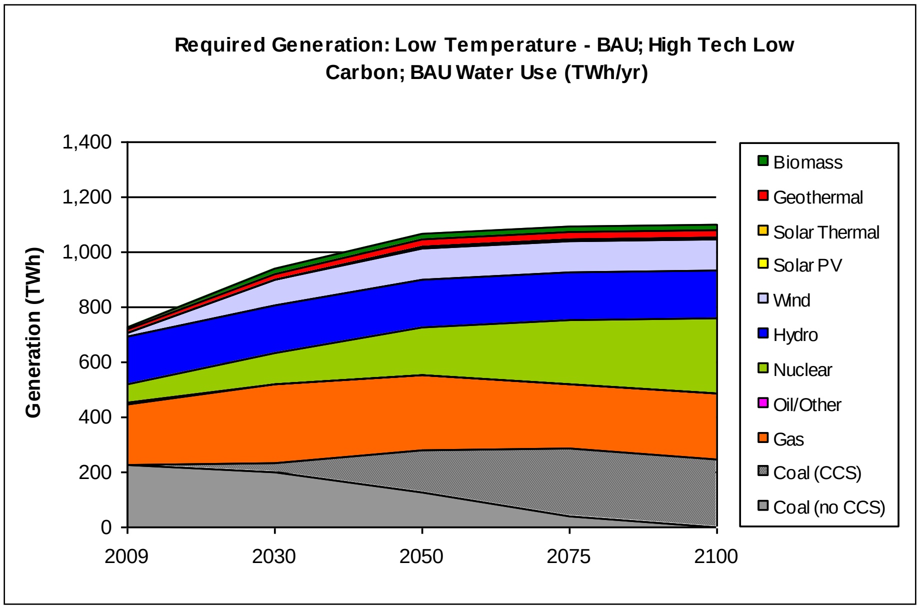
In Scenario 2, water consumption is controlled by 2050,



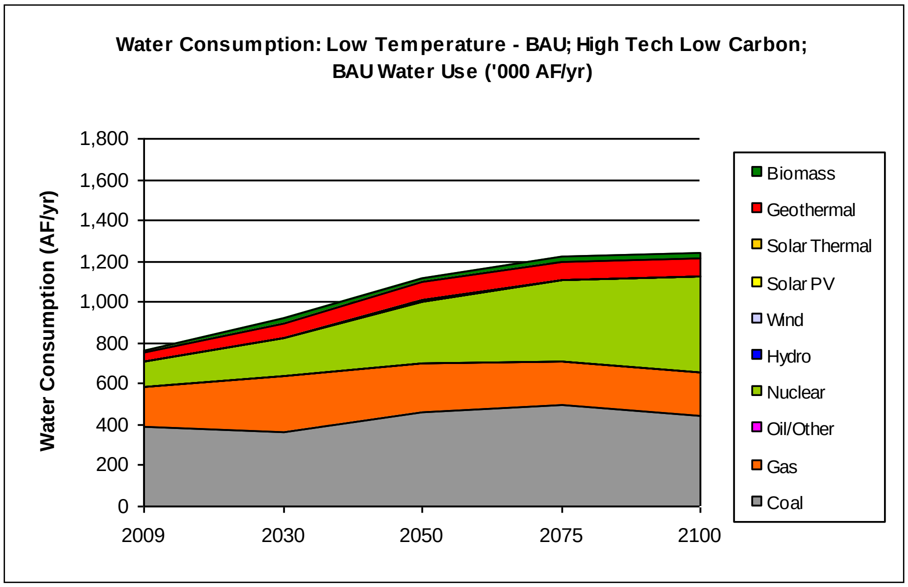
with a cost to consumers to install and operate retrofits on thermal units. CO_2 emissions rise moderately more than in Scenario 1 due to losses of efficiency at dry-cooled units.



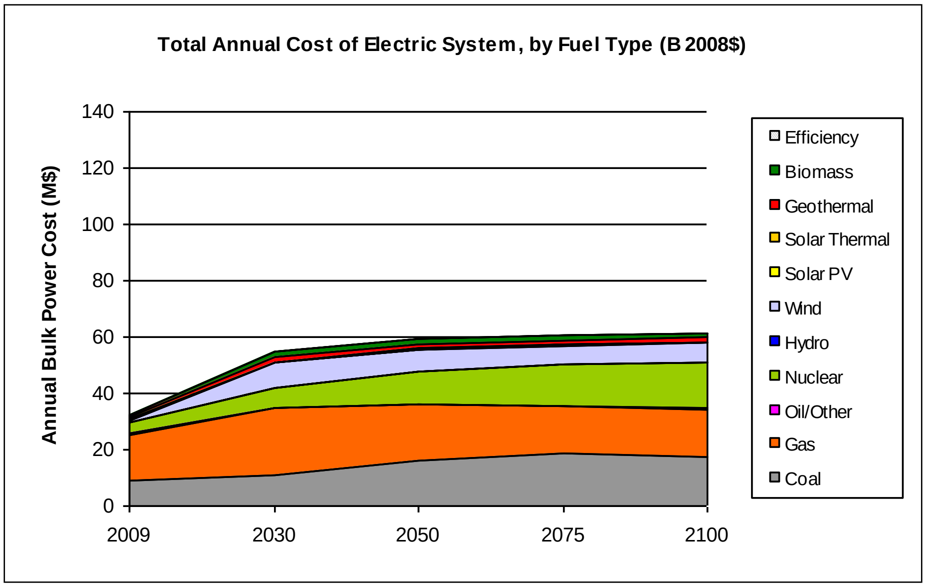
Scenario 3 changes the character of the fuel mix through 2050 and beyond, adding much more nuclear generation, phasing out some coal consumption, and retrofitting the remainder as CCS



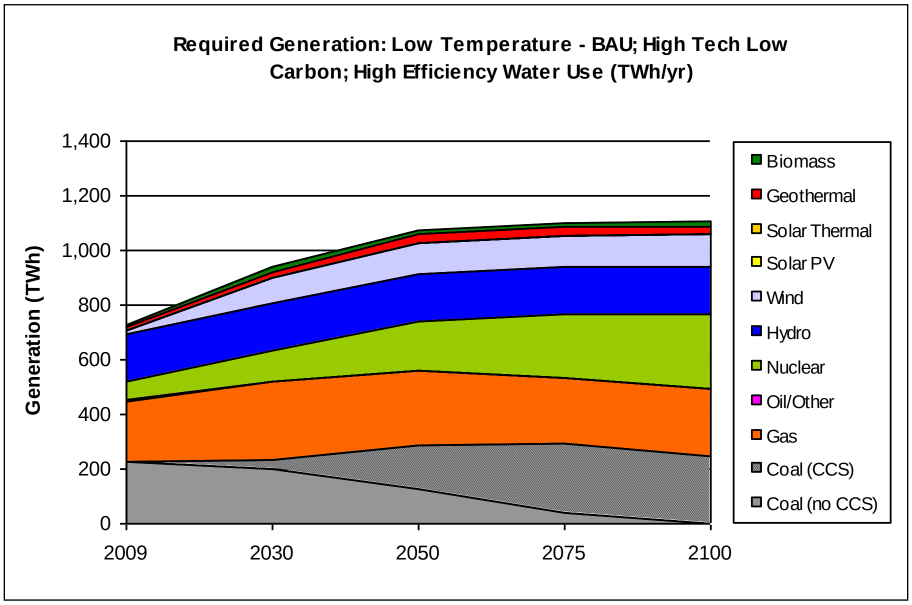
While CO_2 emissions fall to 45% of current emissions by 2100, the water penalty of this transformation is dramatic:



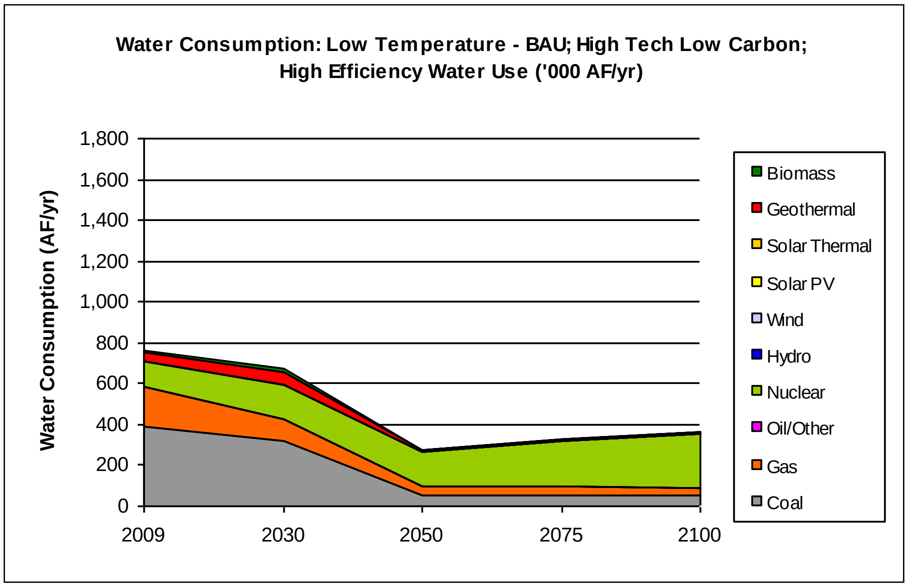
and the bulk cost of electricity is about 20% more expensive than the baseline scenario from 2030 through the end of the analysis period.



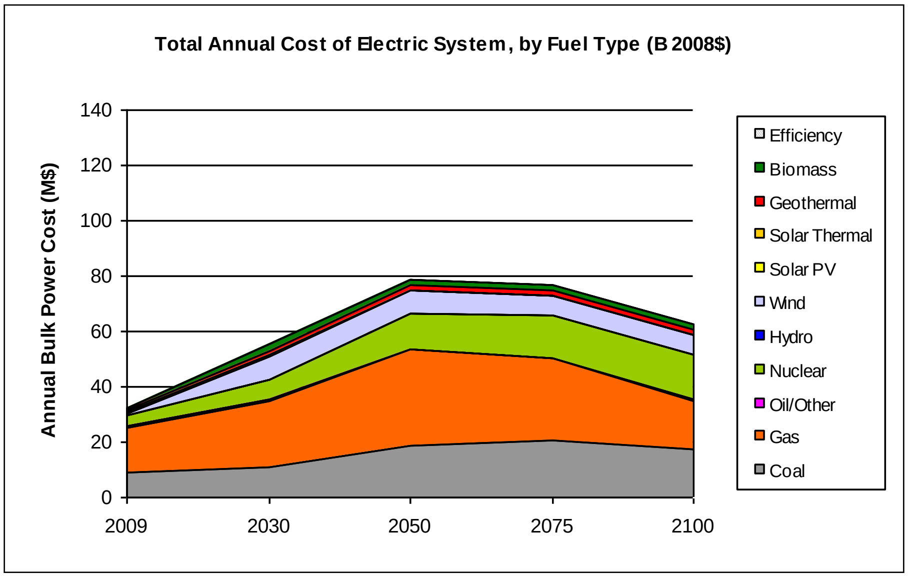
In Scenario 4, controlling for both water and carbon, the fuel mix looks similar to Scenario 3:



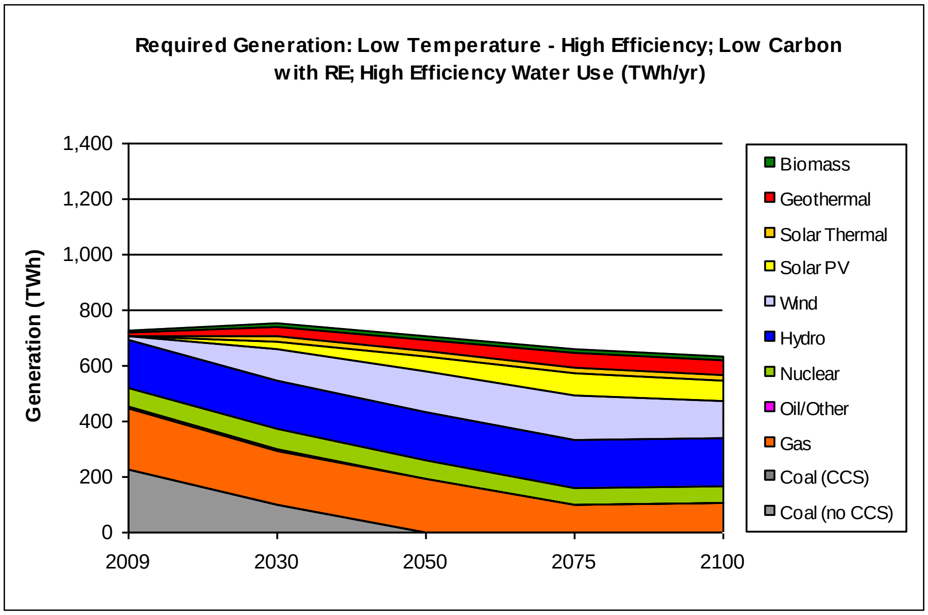
Water, however, is controlled quite significantly. Nuclear units are not able (as far as we understand today) to reliably use dry cooling technologies, so a majority of future water consumption at energy plants is for use at the nuclear fleet. There is also less certainty as to how much water a CCS system might require if it were fully dry cooled. This analysis assumes that this technological option will eventually exist.



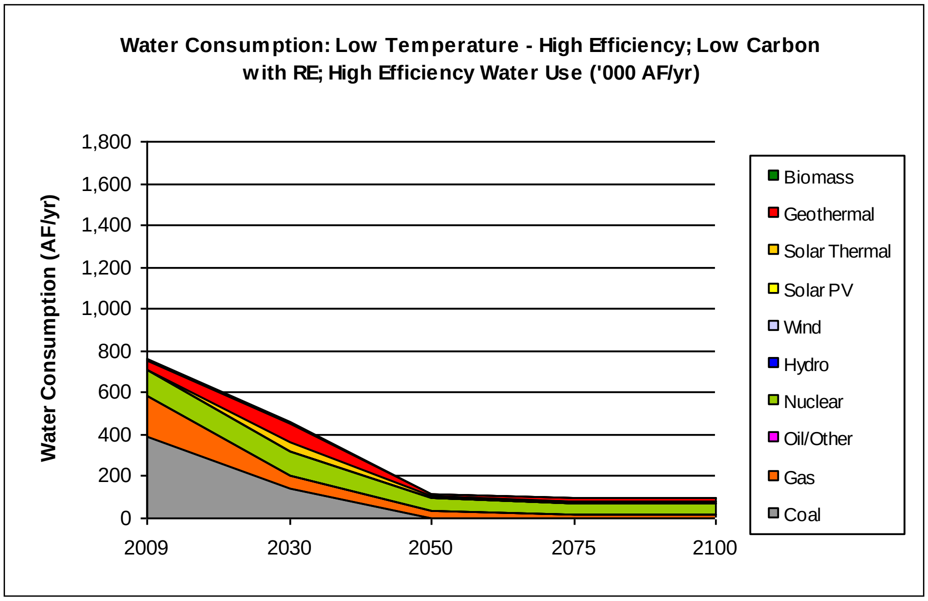
The cost of this solution rises to $80 billion on an annual basis by 2050, about 50% more expensive than the baseline.



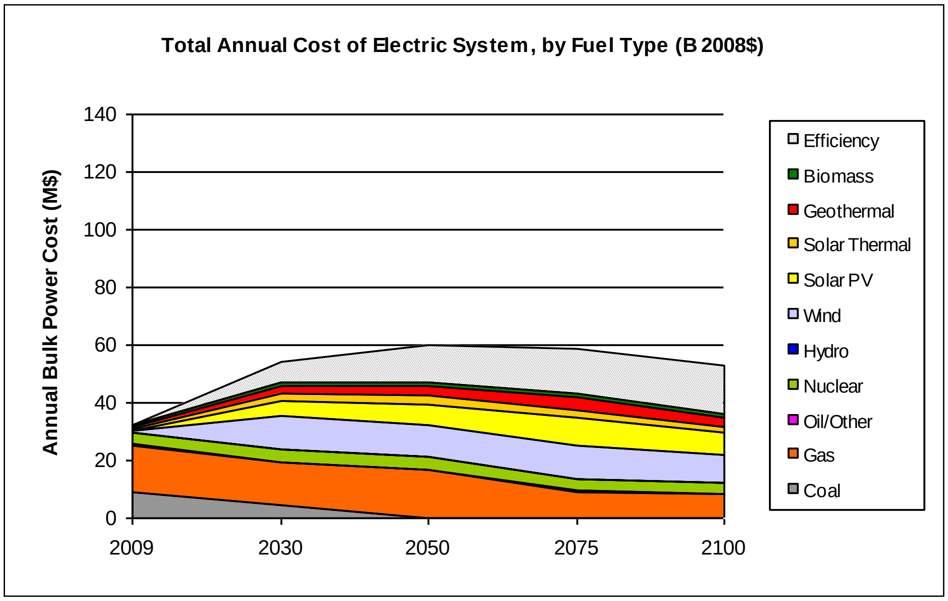
In the last of the core scenarios, Scenario 5, reducing carbon and water through renewable energy and efficiency and water retrofits, demand sinks over time, and we are able to phase out the full coal fleet through 2050, and increase renewable energy fractions to about 50% by 2050 (not including large hydroelectric, which would yield closer to a 75% fraction of non-fossil or uranium-based generation.



Water consumption in this scenario falls dramatically by 2050.



CO_2 emissions fall to less than 20% of 2010 emissions by 2075. The cost of this scenario exceeds the BAU by 7% in 2030 and 16% through 2075. Much of the cost of this scenario is in the energy efficiency component, spending on significant energy reductions.


Total Annual Cost of Electric System, by Fuel Type (B 2008$)
Annual Bulk Power Cost (M$)
140
120
100
80
60
40
20
0
2009
2030
2050
2075
2100
Efficiency
Biomass
Geothermal
Solar Thermal
Solar PV
Wind
Hydro
Nuclear
Oil/Other
Gas
Coal

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