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Is there a water–energy nexus in electricity generation? Long-term scenarios for the western United States

Frank Ackerman*, Jeremy Fisher

Synapse Energy Economics, 485 Massachusetts Avenue, Suite 2, Cambridge, MA 02139, United States

HIGHLIGHTS

- We model long-run electricity supply and demand for the western United States.
- We evaluate the costs of carbon-reducing and water-conserving scenarios.
- Carbon-reducing scenarios become cost-effective at carbon prices of \$50–70 per ton CO_2.
- Water-conserving scenarios are only cost-effective above \$4000/acre-foot of water.
- Electricity planning is central to climate policy, but much less so to water planning.

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Abstract: Water is required for energy supply, and energy is required for water supply, creating problems as demand for both resources grows. We analyze this "water–energy nexus" as it affects long-run electricity planning in the western United States. We develop four scenarios assuming: no new constraints; limits on carbon emissions; limits on water use; and combined carbon and water limits.

We evaluate these scenarios through 2100 under a range of carbon and water prices. The carbon-reducing scenarios become cost-effective at carbon prices of about \$50–\$70 per ton of CO_2, moderately high but plausible within the century. In contrast, the water-conserving scenarios are not cost-effective until water prices reach thousands of dollars per acre-foot, well beyond foreseeable levels. This is due in part to the modest available water savings: our most and least water-intensive scenarios differ by less than 1% of the region's water consumption.

Under our assumptions, Western electricity generation could be reshaped by the cost of carbon emissions, but not by the cost of water, over the course of this century. Both climate change and water scarcity are of critical importance, but only in the former is electricity generation central to the problem and its solutions.

1. Introduction

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" (among many others, Scott et al., 2011; Bazilian et al., 2011; see also King et al., 2008). This nexus of problems is of great importance to the western United States, a fast-growing region with limited precipitation and water resources.

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. 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. Utility plans for capacity expansion could, under some scenarios, require so much cooling water that they will worsen summer water shortages in many parts of the country (Sovacool and Sovacool, 2009). 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. On the other hand, 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

* Corresponding author. Tel.: +1 617 453 7064.
E-mail addresses: fackerman@synapse-energy.com (F. Ackerman), jfisher@synapse-energy.com (J. Fisher).

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northern California is pumped hundreds of miles, over mountains 2000 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 3000 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 (Scott et al., 2011).

Numerous studies have examined interactions between energy and water supply. For example, a detailed forecast of U.S. electricity generation through 2030 finds that introduction of a carbon price will cause no change or a modest reduction in water withdrawals, but a significant rise in water consumption (Chandel et al., 2011). In this forecast, a carbon price induces a shift toward CCS at fossil fuel plants, and toward more use of nuclear power; both of these technologies increase water consumption, compared to the existing mix of generation facilities.

Addressing a similar question, we adopt a different research strategy, developing alternative long-run electricity generation scenarios for the western United States—a region that includes the driest and most water-stressed parts of the country.[1] Our scenarios adopt differing generation technologies, based on four differing assumptions about future resource and policy constraints: no new constraints; limits on carbon emissions; limits on water use; and the combination of both carbon and water limits. We then examine a range of prices for carbon emissions and for water consumption, to identify the prices at which each scenario becomes cost-effective (in effect, finding the shadow prices for carbon and water that are implicit in each scenario).

2. Model design

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 model 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. The purpose of this model is to sketch out how the region's electric demand and supply might evolve over a very long planning horizon (to 2100), and what impacts this evolution might have on electricity cost, carbon dioxide (CO_2) emissions, and water use.

The model estimates demand from 2008 through 2100, driven by population, temperature changes, and assumptions about energy efficiency. For each scenario, the model deploys resources to meet the demand, and estimates required generation, bulk power system costs, CO_2 emissions, and electric-system water consumption. It calculates annual (and for selected data items, seasonal) values in 2030, 2050, 2075, and 2100.

The model is driven by user-specified technology choices, not by a cost-minimizing optimization procedure. 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.

In general, the model makes relatively simple, state-level projections of demand. In contrast, it provides facility-level detail on supply technologies, costs, and plant performance, extrapolated to describe the evolving electricity sector needed to meet demand through 2100 under each of the scenarios.

2.1. Electricity demand assumptions

Electricity demand is modeled at the state level, based on forecasts of population, per capita demand growth, energy efficiency measures, and responses to changing temperatures.

2.2. 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.

2.3. Per capita demand growth

Electric consumers in the United States use increasing amounts of electricity each year. 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, 2010a), 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 per capita demand will remain constant at 2008 levels, in the absence of new energy efficiency measures. We also assume that the industrial, commercial, and residential fractions of each state's electricity demand are constant at 2008 levels.

2.4. Energy efficiency

As explained below, each scenario is modeled both with and without an ambitious energy efficiency initiative. The efficiency assumption, when used, is comparable to results achieved by existing energy efficiency programs: per capita consumption is reduced, initially at a rate of 1.06% annually. That rate drops to 0.90% annually after 2030, 0.60% after 2050, and 0.45% after 2075.

2.5. Response to temperature

As temperatures rise and fall above and below a comfort threshold, households and businesses use air conditioning and space-heating to maintain comfort. In addition, some states may have seasonal changes in population, e.g. summer or winter vacationers, creating changes in electricity use correlated with temperature (since per capita demand is calculated using year-round average population). Using monthly consumption estimates for each state (EIA, 2010a,b) and population-weighted monthly average temperatures (NCDC, 2010) we estimated residential, commercial, and industrial consumption per capita in each state as a quadratic function of temperature.[2]

The fitted curves for residential per capita demand versus temperature for five states are shown in Fig. 1. The shape of this

[1] This analysis was developed as part of a broader study of the effects of climate change and water scarcity on the southwestern United States (Ackerman and Stanton, 2011). The study was supported by a grant from the Kresge Foundation to the Stockholm Environment Institute, where Frank Ackerman worked at the time. The study's background paper on electricity generation (Fisher and Ackerman, 2011) provides additional statistical detail on a number of the results described here.

[2] A quadratic function of temperature fits the data well, with an unweighted average r^2 across the 11 states of 0.86 for residential, 0.81 for commercial, and 0.61 for industrial consumption per capita; the worst fits were for industrial load in some of the smaller states.

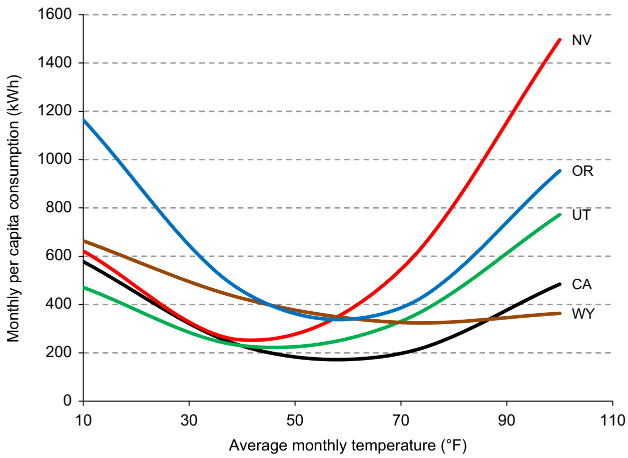

Fig. 1. Per capita residential electricity consumption vs. temperature, selected states.

relationship depends on societal norms, building shell efficiency, and heating and air conditioning systems, and differs by state. The rapidly rising residential demand in Nevada, as temperatures climb above 50°F, is difficult to interpret solely as air-conditioning load, and may include seasonal population changes. California, by far the largest state economy in the region, has a relatively flat curve, reflecting a temperate climate and suggesting efficient use of heating and air conditioning; due to the relative sizes of the states, the regional totals look more like California than like Nevada.

3. Electricity supply data and assumptions

3.1. Power plant data

The supply 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 1 MW of capacity. These generators include thermal units (coal, gas, oil and nuclear), hydroelectric generators, and geothermal projects, as well as large-scale solar installations and wind farms.[3] 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 923.[4]

Water consumption and cooling tower types, where available, are derived from EIA Forms 923 and 860. We assume that solar photovoltaic (PV) and wind plants do not consume any water. For the several hundred thermal units which did not report a cooling tower type, the individual plants were located in Google Earth and their cooling structures were visually assessed. Plants which do not report water consumption or withdrawals are assumed to use water at rates based on their cooling tower types (for details, see Fisher and Ackerman, 2011).

The supply side of the model begins with 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 as needed to meet future demand under the specified scenario assumptions. Three sub-regions of WECC, i.e. California, the Pacific Northwest, and the Rocky Mountain/Southwest states, have very different fuel mixes at present, and the scenarios (described below) assume that many differences by sub-region continue in future years.

Water availability also varies, both between and within these sub-regions. The Pacific Northwest has the greatest abundance of water, while the interior Southwest is the most arid; California is intermediate between the two. Within California, there are sharp differences between the relatively wet northern and dry southern parts of the state. Even more accurate pictures of water scarcity could be developed at the level of individual river basins. Electricity supply, however, is integrated across the 11-state region. In order to match the structure of the electricity system, we have aggregated water supply and demand across many states and river basins. Long-run forecasts predict growing scarcity and excess demand for water throughout much of the region—including both California and the interior Southwest (Ackerman and Stanton 2011)—so the distortions caused by aggregated water modeling may be of secondary importance.

3.2. Forecasting future requirements

Based on the fuel mix, demand, and estimated transmission and distribution losses, the model estimates the required annual generation for the WECC region in each of the analysis years. Total generation required in WECC is distributed

- over the three sub-regions in proportion to generation in 2008,
- into the appropriate resource types based on the scenario assumptions about fuel mix for the analysis year and sub-region, and
- into individual states in proportion to the current distribution of that fuel type among the 11 states in WECC.

Generation by a specific fuel type in a specific state (e.g. coal in Colorado in 2030) is compared to the amount of generation of that fuel type available in the state. If the new amount required is less than the amount already available, generators in the state are assumed to retire or de-rate, starting with the oldest facilities.

As an example, Colorado had 31 coal generators delivering 36.4 million MWh of power to the grid in 2008. If in 2030, the model needs only 33.0 million MWh of power from Colorado's coal-fired plants, the oldest plants would be sequentially retired until 3.4 million MWh was removed. In this case, the model would retire 11 plants, all built between 1950 and 1960.

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 cases in which the model retires existing facilities in the short term, and then builds new resources of the same type in later years.

The model also tracks the effects of gradual retrofitting 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, and assigns them different retrofit costs. Similarly, as plants are retrofitted with CCS in some scenarios, their capital and energy costs and water consumption are distinguished from other plants which have not been retrofitted.

Our analysis focuses on water consumption, rather than withdrawals. This may appear to overlook one of the important impacts of power plants on watersheds, namely the thermal impacts of once-through cooling. In such cooling systems, large quantities of water are withdrawn from a river or other water body, used once, and then returned at a significantly higher temperature, with potentially serious effects on aquatic ecosystems. This issue arises throughout the eastern United States, where water is relatively abundant and

[3] Wind turbines are aggregated to the level of wind farms, or distinct, named multi-turbine facilities.

[4] EIA Form 860 provides plant-level data describing all existing generators; Form 923 provides plant-level data on generation, emissions, and water use.

once-through cooling systems are common. In the western region we are analyzing, in contrast, water is already relatively scarce, and once-through cooling is now restricted almost entirely to coastal power plants (which are being phased out over the next decade). As a result, there are almost no thermal impacts from power plants on rivers and lakes in the western states. Thermal impacts on coastal ocean ecosystems may be significant but are outside the scope of our analysis.

3.3. Resource costs

The costs of new resources are fixed at the estimated price of new resources in 2010; see Appendix A for details. Capacity factors of new plants are fixed at the average capacity factor of the same resource types in WECC in 2010. Solar PV and solar thermal capacity factors are assumed to be 30%. Fuel costs are set at approximately the cost of those fuels in 2008. CO_2 emissions rates are assumed to approximate averages for existing plants of the same type. CCS exacts an energy penalty, modeled as a 35% reduction in a plant's net output (Anon., 2010; Specker et al., 2009).

These cost assumptions are conservative (that is, low for fossil and nuclear plants and high for renewables), reflecting current industry estimates and excluding any future learning-curve effects. For example, overnight capital costs per kW (all costs are reported in 2009 dollars) are assumed to be about $2100 for new coal plants, $3800 for new nuclear plants, $2000 for wind farms, and $4500 for solar photovoltaics (Fisher and Ackerman, 2011). Costs of recently completed coal plants have been well above this estimate, while solar PV costs are widely expected to continue dropping.

Wind is an intermittent resource, requiring backup generation and robust grid technologies to ensure a stable voltage and energy supply. The costs of wind integration are assumed to be proportional to the fraction of demand served by wind, adding $6 per MWh to the cost of wind power when it reaches 20% market penetration.

Capital costs for new facilities, and for upgrades such as new cooling towers or CCS, are amortized over 30 years at a rate of 8.8%. Facilities which remain in use for more than 30 years are assumed to require significant periodic capital expenditure for upgrades and major repairs, equal to 50% of the cost of a new plant every 20 years.[5]

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.

Energy efficiency initiatives have an assumed total cost of $0.045/kWh, close to the high (more expensive) end of what electric utilities are able to achieve today.

4. Scenario definitions

Energy efficiency is the most cost-effective option for emission reduction, and dominates the scenario comparisons if it is used in some but not all of the scenarios. Therefore, we model each scenario both with and without the major efficiency initiatives described above, reflecting some uncertainty about whether this level of efficiency improvement can be achieved. The scenarios are labeled A through D without, and AE through DE with, energy efficiency measures.

4.1. A/AE. Business as usual

This scenario assumes that western states take no specific action (other than energy efficiency in AE) to reduce emissions of greenhouse gases in the electric sector. The regional fuel mix follows the assumptions of the Energy Information Administration's *Annual Energy Outlook 2010* for meeting supply requirements through 2035, and then maintains the same percentage of each fuel through 2100. This results in only limited changes from today's generation fleet; the largest changes are a significant increase in wind penetration (to nearly 25% of generation in California), a moderate increase in coal in the Rocky Mountains and Southwest, and a slight decrease in nuclear energy. Coal, gas, and hydroelectric generation remain the primary fuel types through the end of the century, although non-hydroelectric renewable energy (primarily wind) rises from 5% to 15% of generation.

Assuming that the world, like the Western states, fails to limit carbon emissions, temperatures rise along the IPCC SRES A2 climate pathway. The electric sector makes no specific move to reduce water consumption.

4.2. B/BE. Reduced water use

This scenario assumes that Western states take no specific action (other than energy efficiency in BE) to reduce greenhouse gas emissions in the electric sector, but focus on water conservation. Demand and fuel mix are nearly identical to Scenario A/AE, and the same temperature increases are assumed.

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 retrofitted with wet cooling towers by 2030. Half the coal (as well as biomass) fleet is retrofitted for dry cooling by 2050, and the remainder by 2075. Half of gas capacity is retrofitted for dry cooling by 2030, and the remainder by 2050. It is assumed that nuclear plants must maintain some amount of wet cooling to meet safety standards, so there is a move to hybrid wet/dry cooling operations by 2050.

4.3. C/CE. Cap on carbon emissions

These scenarios respond to an assumed decision to reduce carbon emissions, using somewhat different technologies in the two variants. In Scenario C, the reduction in carbon emissions is achieved primarily through the use of carbon capture and sequestration (CCS) on coal units, along with expanded nuclear and renewable generation. Coal shrinks slightly to 27% of the region's generation (from 32%), while CCS technology slowly expands, reaching 65% of coal generation by 2050 and 100% by 2100. Nuclear power rises from 8% to 14% of generation, while non-hydro renewables, as in Scenario A/AE, increase from 5% to 15%.

In Scenario CE, the reduction in carbon emissions is achieved by an intensive penetration of renewable energy, coupled with natural gas that replaces much of the coal fleet. Elements include the following:

- Retiring all existing coal plants by 2050 (and building no new coal plants).
- Cutting natural gas consumption in half between 2050 and 2100.

[5] This is based on research at Synapse Energy Economics, suggesting that even the oldest existing coal plants still have approximately 50 percent of their debt unrecovered due to upgrades and repairs—although they have long since recovered their initial capital costs.

Table 1
Scenario results, 2100 vs. 2009.

	Values in 2100 (base year 2009 = 100)		
Scenario	Electricity generation	CO_2 emissions	Water consumption
A	146	145	146
B	146	148	27
C	142	46	163
D	142	47	48
AE	89	78	78
BE	89	79	15
CE	86	18	54
DE	86	18	13

- Increasing wind energy to over 20% of generation by 2050, and non-hydroelectric renewable energy to 46% of generation by 2100.

Action taken to curb greenhouse gas emissions, globally as well as regionally, holds temperatures to the IPCC SRES B1 climate pathway. The electric sector makes no specific move to reduce water consumption; on the contrary, increased use of CCS and nuclear power makes electricity generation more water-intensive.

4.4. D/DE. Water and carbon limits

These scenarios assume that both carbon emissions and water use must be sharply reduced. Scenario D combines the fuel choices and CCS adoption rate from Scenario C with the cooling system retrofit (and new construction) requirements from Scenario B. It achieves almost but not quite the combined results of those two scenarios. Because dry cooling exacts an energy penalty in warm climates and CCS technology increases water requirements, CO_2 emissions do not fall quite as low as in Scenario C, and water use does not fall as much as in Scenario B.

Scenario DE combines the energy efficiency and fuel mix assumptions of Scenario CE with the cooling system assumptions of Scenario D.

5. Results

Three indicators of cumulative changes through 2100 are summarized in Table 1. Several of the scenarios accomplish substantial reductions in carbon emissions and/or water consumption; Scenario DE, in particular, goes a long way toward both objectives. Thus, under the ambitious assumptions of Scenario DE, it is technically possible to solve both problems at once. Generation is slightly lower in Scenarios C and D than in A and B (or CE and DE, versus AE and BE), reflecting differing temperature assumptions (IPCC B1 versus A2 climate scenarios); the gap, however, is not large, reflecting limited temperature-sensitive load, especially in California.

Technical possibility, though, does not always imply economic feasibility. To compare the costs of the scenarios, we calculate the present value of total electricity system capital and operating costs from the present through 2100, using a real discount rate of about 5.4%.[6]

With no estimates of externality costs, Scenarios A and AE are the lowest-cost options in their respective groups, with AE considerably cheaper than A. That is, the only “no regrets” options in our analysis are the energy efficiency measures that define the E scenarios. This comparison, however, effectively prices both carbon emissions and water consumption at zero, the price paid by electrical generators today. Zero may not be a good estimate of the market price of these externalities throughout the century, and it is certainly not a good estimate of their social costs at present, let alone in the future.

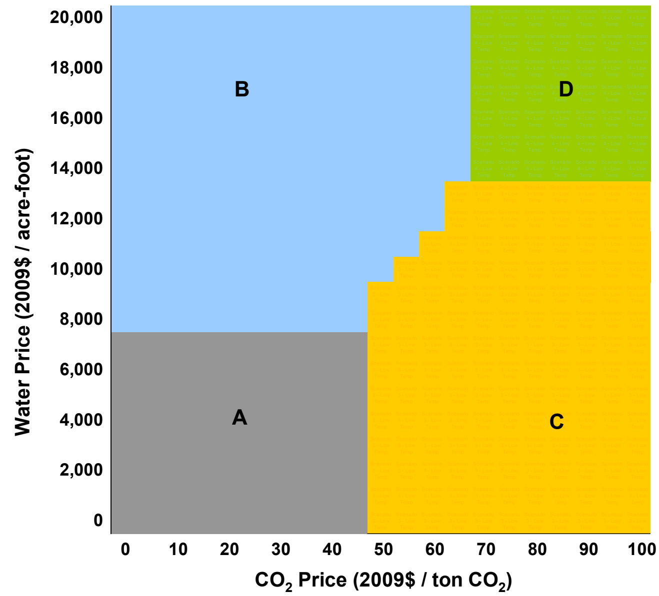

Fig. 2. Least-cost scenarios, without efficiency measures.

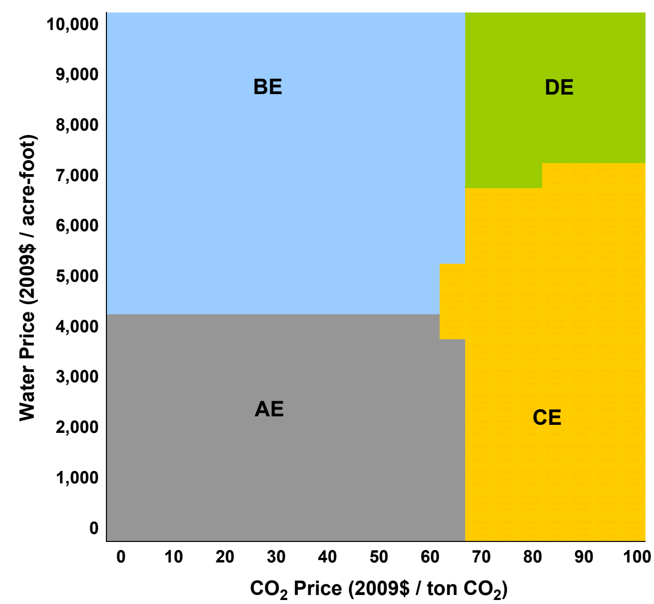

Fig. 3. Least-cost scenarios, with efficiency measures.

To test the effects of externality prices, we repeatedly recalculate the scenario costs, adding various prices for water use and for carbon emissions. Then for each pair of prices, we identify the least-cost scenario. The results are shown graphically in Fig. 2 for Scenarios A – D, and in Fig. 3 for Scenarios AE–DE.

Moving horizontally across the graphs, the carbon-saving scenarios, C and D, or CE and DE, become the cost-minimizing options at carbon prices of \$50–\$70/ton of CO_2. This is broadly consistent with the results of a detailed model of the western North American power system, which found that a carbon price of \$70/ton of CO_2 was needed to induce the sharp reduction in emissions compatible with a 450 ppm climate stabilization

[6] Based on an estimated nominal weighted average cost of capital of 7.5% and an inflation forecast of 2.0% (Synapse Energy Economics, following common utility planning assumptions).

scenario (Nelson et al., 2012), and an earlier study exploring emission reduction in the region's electricity system in response to a carbon price rising to $60/ton (Ford, 2008).While such prices are higher than those envisioned in recent (unsuccessful) U.S. legislative proposals, or the prices that have prevailed to date in the EU Emissions Trading System, they are a plausible level for mid-century or sooner. Many global emission reduction scenarios call for prices significantly higher than this.

In contrast, moving vertically across the graphs, the water-conserving scenarios B and D, or BE and DE, do not become the cost-minimizing options until the price of water reaches the extraordinary levels of $4000–$14,000 per acre-foot. This is far beyond any foreseeable price for water; it is well in excess of the cost of new supplies, or the apparent opportunity cost of current water use. Ocean desalination, for example, is estimated to cost less than $3000 per acre-foot; gross agricultural sales revenue in California averages $1400 per acre-foot of applied irrigation water (Ackerman and Stanton, 2011).

Moreover, the amounts of water at stake are relatively small. The difference between our most and least water-intensive scenarios is only a fraction of 1% of total water consumption in the 11-state region throughout the century. Even in Arizona, where the impacts are relatively largest, the difference between our scenarios never reaches 3% of the state's water consumption.

6. Conclusion

Under our cost assumptions, the carbon-reducing technologies of Scenarios C/CE and D/DE, principally the use of CCS at fossil fuel plants and increased reliance on renewable energy and nuclear power, become cost-minimizing options at carbon prices that are plausible in the foreseeable future. In view of the long life of many power plants, it could be argued that prudent utility planning would already include anticipation of such prices. Certainly those prices are well within the range that is already assumed in ambitious climate mitigation scenarios. Changes in cost assumptions could, for instance, alter the optimal mix of nuclear power and renewables; we do not think that our general conclusion about the cost-effectiveness of carbon-reducing scenarios would be overturned, unless CCS technology proves unworkable or unaffordable.

At the same time, our cost assumptions imply that the water-conserving technologies of Scenarios B/BE and D/DE, such as widespread adoption of dry cooling, get very little bang for a very large number of bucks; they do not appear likely to be part of a least-cost plan for sustainable water use. Many other things can be done at much lower cost per acre-foot of conserved or supplied water.

The “water–energy nexus,” in short, might be better understood as two distinct problems that intersect, quite asymmetrically, with energy planning, and call for quite different responses. This is not to say that future water constraints can be ignored; they pose serious problems for agriculture, and for household and other urban water users, especially in the largely arid region of our study. The region's water crisis, however, does not originate in, and cannot be solved in, the electricity sector. On the other hand, electric power plants are inescapably central to the problem of carbon emissions, and to any potential solution.

Appendix A. Power plant capacity and energy cost assumptions

See Table A1.

Table A1

	Delivered fuel costs ($/MMBtu)	Total overnight cost in 2009 ($/kW)	Variable O&M cost ($/MWh)	Fixed O&M cost ($/kW)	Heatrate (btu/kWh)
Coal	$2.00	$2078	$ 4.69	$ 28.15	9200
Gas (Advanced CC)	$8.00	$990	$2.69	$7.17	6470
Oil/other	$20.00	$984	$2.11	$12.76	7196
Nuclear	$1.70	$3820	$0.51	$92.04	10,488
Wind		$1990	$ 5.50	$13.70	
Solar PV		$4550	$–	$68.00	
Solar thermal		$3687	$–	$68.00	
Geothermal (Binary)		$4046	$4.55	$47.44	
Biomass IGCC	$2.00	$2997	$4.00	$150.00	10,500
Existing coal with CCS	$2.00	$4402	$11.14	$41.22	12,534
IGCC with CCS	$2.00	$3776	$4.54	$47.15	10,781

Sources:
Delivered fuel costs:
Assumed, based on late 2010 prices.

All other costs:
Coal, oil, nuclear: (U.S. Energy Information Administration, 2010a, Table 8.2)
Gas, wind, solar, geothermal, biomass: (Klein, 2010)
Coal with CCS, IGCC with CCS: (Geisbrecht, 2008).

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