Transition Plan — Policies

CLEAN ENERGY VISION PROJECT

Lower Risk, Lower Cost Electric Service:
Policies Western States Can Build On

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CHOOSING OUR FUTURE TODAY

Western states will invest at least $200 billion over the next 20 years, to maintain and enhance electric service. Policy choices we make today will largely determine the characteristics and impacts of electricity delivery for the next several decades.

To inform those choices, our study, Western Grid 2050 (August 2011), contrasted a Business As Usual approach to this investment with a Clean Energy Vision for the West.[1] Continuing on a BAU development trajectory is highly likely to increase costs, risks, liabilities, emissions, water use and health impacts of generation and transmission.

Greater utilization of clean and efficient resources, in contrast, can begin to decentralize electric service, in order to increase security and improve reliability. Moving away from fossil fuels decreases environmental and health impacts and reduces fuel price and supply risks and liabilities. Building a clean energy economy can stimulate local economic development, foster new technologies and new industries, and enable us to regain economic competitiveness.

Large majorities of people in every state continue to express strong preferences for clean air, reduced emissions and water use, greater reliance on non-polluting resources, and for protecting the natural beauty of the West. As a result, states have already taken several policy steps toward clean power.

All of the policies presented here are already being used in one or more western states. Public and private decision-makers can build on this experience to expand utilization of clean and efficient resources.

They have great flexibility in doing so. Moving from BAU to a clean energy development trajectory can follow different policy pathways, unique to the needs and circumstances of each state.

This document is intended as a policy reference tool to this end. It outlines the range of policies available to guide orderly transition to a more secure and sustainable energy future.

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[1] In addition to Western Grid 2050, other Clean Energy Vision project documents include, *Modernizing the Grid: How Our Electric System Can Welcome New Resources, Improve Reliability and Reduce Costs.* All are available at: http://www.cleanenergyvision.org.

1. Diversifying Resource Portfolios

Most western utilities now get more than 90% of the electricity they provide from just four resources: coal, gas, hydro and nuclear. Diversifying resource portfolios can provide economic, security, environmental and reliability benefits. Regulators have strong grounds for setting goals that encourage or require utilities to add clean resources to their portfolios. Making room for more efficient, less risky and more sustainable resources means retiring coal and using gas-fired generation differently, to supply operational flexibility rather than energy.

Moving away from coal and gas will take many years. To ensure orderly transition, procurement planning can begin now. This section describes the most effective policy measures for diversifying resource portfolios.

Integrated Resource Planning

IRP creates a level playing field for evaluating costs and benefits of energy efficiency and demand resources alongside generation resources, in terms of what and how each contributes to reliable system operation, on a risk-adjusted basis. Economic evaluations performed according to IRP principles have led to expanded utilization of energy efficiency and demand resources in several western states. This has helped to reduce system cost and environmental impacts.

Such planning can now be expanded to integrate new demand and supply resources, including Distributed Generation, electric vehicles, Smart Grid infrastructure, Combined Heat and Power, electric and thermal storage, and the transmission needed to access and deliver large-scale renewable generation.

Energy Efficiency

Saving energy — getting more work out of every kilowatt-hour of electricity, therm of gas or barrel of oil — is by far the least expensive way to reliably meet our energy needs. The challenge for regulators is to institute policies that make it profitable for utility companies to help all classes of customers save energy.

To be effective, energy efficiency policies must protect utility profitability from effects of selling fewer kilowatt-hours, and utilities must have incentives to pursue consumer energy efficiency and utilize demand resources on the consumer side of the meter. Commissions must ensure that energy savings programs are designed to produce durable savings, and that results are independently verified.

These policy mechanisms — already in place in some western states — provide a foundation for continuous increase in energy savings:

- Decouple electricity sales from utility earnings. This is a first step in any energy efficiency policy program. Decoupling does not provide positive incentives for utilities to help customers save energy. But, crucially, it does allow utilities to earn financial returns without increasing the amount of electricity they sell.

- Allow utilities to recover prudently-incurred costs of implementing international best practices for energy efficiency programs. Alternatively, to ensure that energy savings benefits accrue to consumers, programs can be administered by third party organizations rather than by utilities.
- Institute regulatory structures that allow utilities to share benefits created when they execute consumer efficiency and demand management programs and projects to the benefit of consumers and the system as a whole.
- Institute incentives, and symmetrical penalties, to encourage utilities to exceed energy efficiency and demand resource savings program targets, both in volume and calendar schedule.
- Incorporate achievement of energy efficiency program savings targets meeting international best-practice standards into determination of need for new generation.
- Develop programs of continuous improvement in energy efficiency standards for appliances and buildings. Standards set enforceable targets for reducing energy use and provide effective mechanisms for improving energy efficiency. The costs of meeting them are appropriately borne by developers, builders, building owners, tenants and equipment manufacturers rather than by electric and gas customers.
- Adopt goals and policies to promote development of zero net-energy new buildings and, separately, low energy building retrofits. Zero net-energy buildings generate as much energy as they consume. Zero-energy building design has great potential to reduce energy use. New technologies make such buildings increasingly cost-effective. Formal investigation of zero-energy buildings by state regulators can call attention to this potential and lay the groundwork for eventual standards that set targets for their deployment.

Large-Scale Renewable Energy and Transmission

Renewable resources reduce fuel price and supply risks and drive down system operating costs. NREL's Western Wind and Solar Integration Study (May 2010) found that adding 30% wind and 5% solar into the generation mix of a six-state area of the West reduced operating costs for the entire WECC region by $20 billion per year. In addition, because solar, wind and geothermal generation have no fuel costs, the marginal cost of dispatching them is very low or zero. As a result, adding these resources drives down wholesale power prices. Diversifying utility portfolios to include more renewables is a prudent investment, both short-term and long.

All but two western states have Renewable Portfolio Standards, or minimum purchase requirements in place. Almost all of these states have increased their targets for adding wind, solar, geothermal and small hydro generation since first enacting standards, for a variety of economic development, public health and public preference reasons. Along with energy efficiency programs, greater reliance on renewable resources forms the core of an electric system free of fuel price and supply risks and environmental and public health costs and liabilities.

Many policy mechanisms are available to reduce the cost of meeting RPS targets for adding renewables. Several states have identified Renewable Energy Zones having high densities of high quality resources. Focusing development into low-conflict zones minimizes land and habitat impacts, minimizes the transmission needed to access that power, and minimizes the risk that transmission built to a zone will go less than fully utilized. Market design and system operational policies also directly affect the cost of adding renewables; they are discussed in a separate section below.

Accessing and delivering large-scale renewable energy to customers across the West will require investment in expanding and modernizing the transmission grid. The benefits of such investment and reasons it can be good for consumers are outlined in, Modernizing the Grid: How Our Electric System Can Welcome New Resources, Improve Reliability and Reduce Costs, Western Grid Group, July 2012, available here.

States can encourage development in zones by performing environmental impact analyses for entire zones. Zone-level analysis can help reduce permitting time without weakening environmental siting standards. Shorter permitting times reduce development costs and ultimately the cost customers pay for renewable power. Zone siting and permitting best practices are outlined in Section 6 below.

Demand Resources

Equipment and appliances on the customer's side of the meter can be operated to supply energy, capacity and other electrical services to the grid. Many western utilities pay customers who voluntarily agree to curtail their electric use in system emergencies or at peak times. Energy service companies aggregate individual customer curtailment into large blocks. Such Demand Response programs have proven to be highly cost effective. They provide substantial environmental benefits compared to meeting peak needs with fossil generation, and can reduce system costs to the benefit of all users. More than 14,000 MW of Demand Response programs — 10% of total system capacity — have won regular bidding to supply capacity in Pennsylvania-Jersey-Maryland Interconnection (PJM) auctions. Similar programs enable customers to participate in New York and New England markets.

In addition to simply reducing energy use at certain times, demand resources can provide many other services to increase system flexibility, reduce cost and improve environmental performance, such as responding to system over-generation conditions by increasing load. Policy mechanisms to promote greater utilization of demand resources include:

- Compensate demand resource reductions at the same rate as generation. Grid operators in some regions of the country now do this.
- Ensure that wholesale market operations do not discriminate against demand resources. Encourage participation of aggregated demand resources in those markets to provide frequency regulation, system balancing and other system services.

- Allow utilities to recover prudently-incurred costs of study, innovation and demonstration of feasibilities of using demand resources for frequency regulation and system balancing.

Distributed Generation

Small-scale photovoltaic (PV) systems and other forms of clean distributed generation provide low-emissions power in city centers and avoid the often substantial costs of importing electricity into densely populated areas. PV output available when electricity use peaks in the afternoon relieves strains on the grid. Decentralizing electricity generation reduces system vulnerabilities and improves security. Advanced controls and two-way communication between grid operators and distributed generators can increase system reliability. Combinations of large-scale renewable energy generating projects and smaller distributed generation may in the future be able to supply most system energy and many of the electrical services necessary to keep the system balanced in all hours.

Generating power on rooftops and disturbed sites in cities provides environmental benefits, compared to fossil-fired generation or large-scale wind or solar production at greenfield sites. DG deployment programs create many jobs and drive improvements in many clean technologies. Network upgrades may sometimes be necessary to support large DG penetrations, but the benefits of decentralizing generation often outweigh such upgrade costs.

Many different policies are in use to encourage, support and finance DG deployment:

- Simplified "plug and play" interconnection standards, which can reduce the time and cost of deploying DG. Regulators can require utilities to provide short, simple interconnection application forms, and direct them to connect small systems in periods of months rather than years.

- Net metering. The most common state policy, net metering allows customers to offset their electricity demand with power they generate on site. In effect, residential and commercial customers net their PV or small wind production against their electricity use, usually over 12-month periods. If customers produce more electricity than they consume over the course of a year, some net metering programs pay them for the excess at the same price per kWh that utilities charge them for electricity.

- Solar leases. Solar companies active in many western states now offer to purchase and install residential (and some commercial) PV systems and lease them to homeowners. This allows customers to avoid upfront capital investment costs and spreads PV system payback over 10-20 years. As a result of solar leasing, middle class families now make up the largest portion of the solar installation market in California.

- Property Assessed Clean Energy (PACE). DG systems can be financed through building mortgages, property taxes, municipal bonds and by other low-cost, long-term mechanisms that keep these costs separate from electric rates. State commissions can work with mortgage lenders, builders and city officials to have DG deployed in ways that reduce rather than raise electricity bills.

- Feed-in Tariffs. To jumpstart small-scale PV deployment, Feed-in Tariffs pay clean energy generators a fixed price, generally based on cost of generation plus a reasonable rate of return, for a set period of time. Some states, and some countries, have set ten-year schedules of prices to be paid for PV generation, with the price declining each year until the price is the same as system power in year ten. This gives PV manufacturers market certainty for a long enough period to justify investment in reducing PV costs.

- Standardized permitting. Fire code, inspection and other requirements — and permit fees — vary widely from city to city. Unique and unnecessarily complicated permitting requirements can add $2,500 to the cost of residential solar installations. Permit preparation time and cost pose a substantial barrier to wider DG deployment. Standardized permitting processes can drive such costs down.

- Building standards. State legislatures, and some commissions, can institute building standards that encourage no-carbon DG to be incorporated in building design and construction, and which require building siting and orientation to consider solar generating potential and passive solar heat gain and loss.

Combined Heat and Power

CHP produces electricity, heating and cooling from the same fuel source and thus greatly improves overall fuel use efficiency. Solar CHP technologies are being developed that provide heat and power from the sun's energy, without fuel use.

CHP has been used in cities and at industrial sites around the world for several decades and has proven cost-effective. It can reduce or eliminate the need for transmission lines to those areas. It can anchor local distribution circuit operation, to support decentralization of system balancing functions away from large central station power plants. With overall energy efficiencies of 80%-90%, CHP has significant environmental advantages.

CHP can also contribute to electric system flexibility. Denmark, for example, is retrofitting its Combined Heat and Power plants with electric boilers to provide storage and flexibility, and CHP plants there respond to flexibility signals in power and regulation markets.

CHP deployment can be quickly expanded if policy barriers are removed. Most CHP facilities today have been developed and are owned by industrial companies and non-utility generating companies. Where utility companies do not own CHP facilities, they often view them as a source of lost sales and work to limit their deployment. Rate structures and incentives often do not reflect the overall energy efficiency and societal value (including avoided transmission expense) CHP can provide.

Policies to address these barriers and support CHP development include:

- Add CHP to RPS programs. States can set targets for CHP capacity to be installed, as a component of renewable portfolio standard programs.
- Eliminate standby rates and demand ratchets in standard rates. Demand charges and standby rates that do not track electricity usage often penalize both CHP and DG. Such rates create disincentives for energy efficiency and deployment of onsite generation. Rates that reflect electric system benefits of on-site customer generation and are both fair and rational are critical to long-term success of innovative energy options.
- Explicitly value social benefits. Because of their higher overall energy efficiency, CHP facilities produce electricity, heating and cooling with lower rates of emissions than stand-alone gas or coal generating plants. In some cases, they can be sited to avoid the cost of new transmission. Including consideration of these benefits in procurement decisions is likely to support CHP development.

Coal Transition Planning

More than half of western coal plants are significantly older than their design lives. Large new investments in pollution control equipment to meet Clean Air Act emissions requirements are uneconomic for many of these old plants. Some western utilities have begun planning to retire these facilities and have signaled state regulators to expect plants to be retired. The North American Electric Reliability Corporation (NERC) estimates that more than 20% of US coal generating capacity could be retired within the decade.

State policies can ensure orderly transition away from uneconomic coal plants. This includes compensating plant owners for the remaining book value of the units to be retired. It also includes directing utility company procurement planning to anticipate coal unit retirement. Such planning can give utilities and regulators sufficient time to find ways to avoid making uneconomic coal plants into "Reliability Must Run" units which would have to remain in operation at above market costs. Policies can ensure that non-fossil resources get equal consideration alongside gas in planning to replace coal power, including use of the transmission facilities freed up by retiring coal units. More specifically:

- Require utilities to disclose climate damage liabilities and litigation risks to investors, based on directors' fiduciary responsibilities to inquire and management's duty to describe these risks in securities filings.
- Use rate case, procurement and IRP proceedings to develop utility-specific plans to retire coal units and replace that power with non-polluting, non water-intensive resources.
- Initiate settlement agreements that recover utility costs and provide net benefits to consumers from early retirements, amending contracts as necessary.

- Require utilities to demonstrate that pollution control retrofit expenditures deliver superior, long-term benefits to consumers and the public compared to a diverse portfolio of cleaner resources.
- Require costs of new pollution control equipment to be amortized quickly. (The Nevada PUC, for example, allows seven-year amortization of these costs). Require utilities to develop plans for phased, orderly retirement of all coal plants, in ways that obviate continued operation of those plants for local reliability purposes.
- Require studies to determine how much renewable energy can be transported on transmission lines now carrying power from coal plants likely to be retired.

Replacing Coal with Gas: Prudency Concerns

Low gas prices in 2012 are encouraging utilities and state commissions to replace older coal plants with gas-fired combined-cycle units. This is a risky proposition. Gas prices are at, or in some regions, below the cost of production. With little or no ability to decline further, prices can only rise. LNG export possibilities, economic expansion and greatly increased use of gas by US chemical and other industries exerts upward price pressure. Expanded use of gas for electric generation will require hundreds of billions of dollars of investment in new pipelines and gas storage facilities. Many studies show the cost of required new infrastructure, and thus the delivered cost of gas, as likely to increase electricity costs by substantial amounts.

Expanded use of gas also increases environmental risks, costs and liabilities. Replacing even half of coal generation with gas will require drilling tens of thousands of new wells every year, with attendant road construction, land use and air quality impacts. Substantial uncertainties surround shale gas production, including groundwater contamination, water use and wastewater disposal, seismic effects and local air pollution. Expanded fuel transport carries inherent safety risks, as shown in the frequency of pipeline leaks and explosions. There is ample reason to question the security and sustainability of gas supply.

From a climate disruption and carbon emissions liability perspective, replacing coal with gas may provide minimal or even negative benefit. Burning gas produces roughly half the CO_2 as burning coal. But because methane has about 25 times the global warming effect of CO_2 over a period of about 100 years,[2] very small leakage of unburned gas into the air makes the climate effect of gas equal to that of coal combustion (plus coal-bed methane leaks). Current scientific analysis shows that methane leaks would have to be held to 3.2% or less for natural gas to have less of a climatic impact than coal. Drilling-rig operator reported production data shows that leakage at 80% of US drill sites to be 2.6% or greater. In combination with downstream leakage, in transfer to tank trucks, pipeline compressor stations and other points in the gas delivery chain, it is likely that total leakage exceeds the 3.2% threshold beyond which gas becomes worse for the climate than coal, at least out to a hundred-year timeframe.

[2] http://en.wikipedia.org/wiki/Global-warming_potential

Gas has a strategic role in ensuring reliable system operation. But there are compelling reasons to replace coal with portfolios of less risky and more sustainable alternatives — energy efficiency, demand resources, renewables — that in combination can supply the range of electrical capabilities needed to build a more secure grid.

Gas-Fired Generation for Flexibility, Not Energy

The flexible operating characteristics of gas turbine technology give gas-fired generation important roles, both during transition away from coal and in very low-carbon electric systems.

Much of the gas-fired generating capacity installed in western states is underutilized. The cost of these units is already included in the prices we pay for electricity. As coal plants are retired, these gas units can run more, to replace some of the power that was generated by coal. Given the amount of gas-fired generation already installed, few new combined-cycle gas units are likely to be economically justified.

As renewable energy and demand resources come to supply the majority of energy on the system, gas generation can fill in around the power provided by those resources to ensure reliable electricity in all hours and in all regions.

Procurement of gas generation, even at the beginning of the transition, should focus on machines that have low emissions and great operational flexibility: ability to start up quickly, ramp up and down quickly, and operate at part-load without much loss of efficiency. Specific policy mechanisms include:

- Optimize procurement of flexible gas resources. Catalogue heat rates, ramp rates and operations and maintenance records for existing gas generators. Determine which gas units have the ability, or can be retrofitted to supply system needs most cost-effectively. Compare flexible gas generation to non-fossil sources of flexibility including DR, dispersed wind and solar generation, geothermal and solar thermal with storage.
- Evaluate changes in gas forecasting, scheduling, and nomination procedures needed to integrate larger amounts of wind and solar generation. Determine whether net consumer benefits would be achieved by adding additional gas storage for reliability and flexibility. Implement continuous improvement policies to reform gas operations that contribute to reliable electric service and least cost integration of Variable Energy Resources.
- Monitor gas market price fluctuations, shale gas completion and depletion rates, and shale gas environmental issues to assess long-term gas availability and cost trends.
- Develop mechanisms for dispatching generators that incorporate GHG and criteria pollutant costs as well as marginal energy costs. Such dispatch algorithms will help jurisdictions minimize emissions.

2. Grid Operations and Markets

Control of the grid — power plant dispatch, power flows on transmission lines and the instantaneous balancing of supply and demand — is balkanized among 37 Balancing Areas across the western US. The power plants and other resources called on to run are determined largely by bi-lateral contracts between utility companies, and between utilities and merchant generating companies, mostly on an individual service territory basis. This operational and market structure obscures real-time power flows and thus makes it impossible to utilize existing transmission fully or efficiently. This makes system reliability more difficult to ensure and leads to unnecessary transmission construction.

Straightforward changes in industry practices and policy, a few of which are summarized below, can increase grid flexibility, improve reliability, reduce costs to consumers, and accommodate larger amounts of clean power.

Energy Imbalance Market (EIM)

Actual demand for electricity in each hour is usually slightly different than forecast, and actual power generation is often less or more than scheduled. Creating a western regional market and centralized dispatch to supply these imbalances allows the most efficient generators to run more, the least efficient to run less or not at all. It decreases the amount — and associated substantial cost — of operating reserves each utility must carry. It allows utilities to meet regulation needs more cost-effectively, from a much larger pool of generators across the region, thus reducing the burden on individual Balancing Areas. It makes much more efficient use of existing transmission. And it provides real-time power flow information system operators need to improve reliability.

EIM potential cost savings and reliability improvements warrant an active role for commissions, consumer advocacy groups — and city councils or boards of directors in the case of publicly-owned utilities — in convincing utilities in their states to participate.

Consolidating Balancing Areas

The western US electrical grid today is divided into 37 Balancing Areas (BAs), many of them very small, some with only generators and no load. Each BA is responsible for maintaining demand-supply balance, measured in terms of system frequency, in its area. This requires each BA to maintain generating units in reserve, in case of outages, and limits the resources it can call on to keep the system balanced. Consolidating these functions into one or a few BAs for the entire West would greatly reduce the number of fossil generators needing to be built and held in reserve, and would reduce the number of fossil units operated to provide system balancing. It would also capture the benefits of geographic and temporal diversity of wind and solar projects across large areas of the West. Grid operators in every state would then be able to call on the entire fleet of resources across the West. Coordinating Balancing Area functions in this way would provide major cost savings to consumers, and significant avoided fuel use and emissions.

Obtaining these benefits requires sufficient transmission capacity between and among regions. Balancing Area consolidation thus fosters development of transmission projects that support such expanded resource sharing.

Reducing Costs of Integrating Renewables

The Western Governor's Association June 2012 report, "Meeting Renewable Energy Targets in the West At Least Cost: The Integration Challenge," provides detailed explanations of nine approaches for reducing the costs of adding large amounts of renewables to the western grid. Four of the most effective of these include:

- Faster scheduling and dispatch. Allowing generators to change the amount of power they provide to the grid every five minutes, instead of once every 30 minutes or once every hour (the current practice in most of the western US), enables energy markets to supply operational flexibility at lower cost than is possible with hourly dispatch.

- Increased use of dynamic transfers between Balancing Authorities. Dynamic transfers help take advantage of the geographic diversity of wind and solar output across the West to reduce aggregate variability of those resources. They improve access to balancing resources across the region to reduce costs of integrating wind and solar projects. Dynamic transfers — already in use by many western utilities — can increase operational flexibility and provide more market opportunities and lower overall generation costs.

- Better weather forecasting. Electricity use is driven in large part by weather. Better forecasting improves reliability, while inadequate anticipation of extreme temperatures has led to blackouts. Gas pipelines and compressors, thermal generators and electrical substation equipment sometimes fail to operate in freezing conditions; extreme high temperatures reduce gas generator output and stress system capabilities. More accurate forecasts allow operators to schedule and balance wind and solar generation in ways that save money. Advances now underway can supply vastly improved information to system operators.

- Geographic Diversity. The most effective way to reduce the aggregate variability of wind and solar generation is to install more of it. While the output of a single wind or solar project can be highly variable, the combined output of many such projects is orders of magnitude less variable. Further, wind and solar generation often complement each other, providing power across all or most hours. Facilities spread across larger geographies can take advantage of different weather patterns to the same end. Geographically dispersed projects allow renewables to play larger roles in system balancing, thus reducing the need for fossil resources for such duty.

Coordinated Procurement

Coordinating renewable energy procurement among western power buyers facilitates transmission development by matching the amount of renewable energy to be acquired over the next few years to the capacity of transmission facilities being developed. Coordinated procurement can also help lay the foundation for development of western regional markets for renewable energy. Larger projects typically bring lower costs, so partnering by utilities to gain project scale can lead to lower rates for consumers.

In 2013, the six New England states will issue a joint request for proposals for renewable energy. In approving this initiative, Governors of the states observed that, rather than seeking to obtain renewable supplies state by state or utility by utility, coordinating solicitations broadly would make the process more efficient and potentially less expensive for all.

WGA's Western Renewable Energy Zone initiative is intended, among other things, to provide a basis for coordinating procurement across the region. Renewable Energy Zones are discussed in Section 3 below. Resource planners at some western utilities say that they would gain little from coordinating procurement to meet near-term targets. However, as state and federal policy and WECC planning puts increasing emphasis on zone development, procurement is likely to focus more on such strategic areas. Transmission projects to zones are likely to be larger than most individual utilities can develop or finance by themselves. Proactively coordinating procurement zonally can pool risks and share costs of generation-transmission development.

Western Regional Markets for Renewable Energy

A larger, more liquid market for clean energy will create more competition among suppliers, expand the pool of buyers, and help drive down the cost of wind, solar and geothermal generation. Access to lower-cost power can help minimize costs of adding renewables for all customers across the region, in both importing states and exporting states. A regional market can expand the aggregate economic development benefits of renewable energy development across the West and facilitate sharing those benefits among states.

The Western Renewable Energy Generator Information System (WREGIS) already in operation provides the generation output tracking necessary to support region-wide sales and trades of both energy and RECs (Renewable Energy Credits). Developing regional markets will require supportive policies in each state.

Markets for Ancillary and Other Services

Ancillary services are electrical functions that provide essential system balancing, storage and reliability services. Today they are mostly bundled with fossil generation. Non-fossil resources, including renewable generation, demand response and energy storage technologies, have the potential to provide these services with greater flexibility, less environmental impact and at lower cost. State markets or a regional market — or alternatively, clear and consistent payment policies for ancillary services — will enable clean resources to compete to provide these services, and will support continuous improvement in the efficiencies and performance of these technologies.

Electric heating and cooling technologies that are able to respond to price signals, such as water heating and ice storage, can increase the flexibility of load. Such services help shift or flatten peak loads, thus reducing system costs.

Intelligent Local Networks; Distribution System Open Access

Widespread deployment of Distributed Generation (DG) is a cornerstone of transition to a clean electric system. Given the size and voltage levels of DG installations, most will be interconnected to utility distribution systems in cities and neighborhoods. As electric vehicles penetrate the light-duty fleet, they can also be connected to these distribution networks. Electric vehicles are already being designed to provide storage for off-peak and renewable energy, and to function as providers of grid stability services, with their batteries able to be charged and discharged at optimal times for the grid. Residential and commercial hot-water heaters connected to the grid also have potential to supply significant stability services.

Distribution grids are being engineered to incorporate advanced communications and information technologies that improve the efficiencies of both generation and electricity consumption. Communications, cyber security and engineering standards to provide such functionalities and manage two-way power flows are being developed.

Most distribution circuits today, including their substations and transformers, were designed for one-way power and communications flow: from the centralized grid to local customers. They were not designed to feed power generated locally back to the central grid, or to operate around the clock. To accommodate distributed generation, electric vehicle charging/discharging and utilization of local Demand Resources, many distribution circuits may have to be upgraded.

Several policy mechanisms can guide distribution systems to evolve in ways that support these clean resources:

- Open Access to Distribution Systems. Almost all distribution systems are owned and controlled by utilities. National policy requires transmission owners to provide open access to the transmission lines they own or operate. This provides a level playing field for connection to the transmission network. There is no comparable requirement for interconnection to distribution networks. Developers of distributed generation, including building owners and electric vehicle owners, lack information about local circuit capabilities and are often blocked from installing resources that flow power onto those circuits. Meeting state goals for deployment of distributed generation, demand resources and electric vehicles may require institution of policies that ensure open access to distribution circuits.

- DG interconnection standards for "plug and play" functionality. Protocols and standards must be developed for measuring and evaluating the reliability and cost-effectiveness of distributed generation and distribution circuit-based electric service delivery.

- Distribution Investment. Financing mechanisms can support investment in distribution circuit and distributed generation technologies outside of electric rates.
- Rates and terms of service. Time of use, standby and back up rates should encourage decentralization of load-supply balancing into local generation on distribution circuits. Standard terms of service, including readily understandable interconnection agreements written in plain English should replace lengthy and complex contracts.

3. Planning and Permitting

Existing state RPS policies effectively require new generation and, in some cases, accompanying transmission facilities to be developed. Transition away from coal and gas will require additional development to access and deliver renewable energy, even with the largest feasible amounts of energy efficiency savings and Distributed Generation deployed. Several policy approaches are proving effective in guiding more effective approaches to this development.

Renewable Energy Zones

Renewable Energy Zones (REZ) focus development into limited geographic areas having high quality resources. Properly identified zones can minimize environmental impacts and amounts, and thus costs, of transmission necessary to access and deliver large-scale renewable energy.

Six western states — AZ, CA, CO, NM, NV and UT — have identified such zones, and the Western Renewable Energy Zone (WREZ) initiative of the Western Governor's Association is working to identify priority development areas across the entire West. Zone development supports coordinated procurement, enabling utilities to share costs and risks of accessing large amounts of renewable resources.

The Bureau of Land Management has identified Solar Energy Zones (SEZ) in the Southwest and is completing a Programmatic Environmental Impact Statement (PEIS) analyzing impacts of development in such zones. This PEIS is intended to streamline and simplify permitting for solar generation projects located in SEZ. BLM is also working to identify wind power and geothermal power zones across the West.

For Arizona's Restoration Design Energy Project (RDEP), the Bureau of Land Management-Arizona is preparing an environmental impact statement to identify lands of low resource value for renewable energy development while also establishing baseline environmental protection measures for such projects. RDEP zones emphasize lands that are previously disturbed, developed, or where the effects on sensitive resources can be minimized. Sites nominated during the scoping process include former landfills, brownfields, mines, isolated BLM parcels, and Central Arizona Project canal rights-of way areas.

In California, a joint federal-state effort, the Desert Renewable Energy Conservation Plan (DRECP), is identifying zones based on Natural Community Conservation Planning (NCCP) requirements. Projects sited in such zones will be afforded expedited permitting, thus reducing costs for local, state and federal agencies, generation developers, utilities and consumers while providing the best possible environmental outcomes.

Proactive Transmission Development

In order to meet existing RPS targets in the timeframes mandated, some states have enacted policies to encourage proactive development of required transmission. Other states may also find advantages in doing so.

It typically takes seven to ten years to plan, permit, engineer, construct and place new transmission facilities in service. Wind, solar and geothermal generating projects, in contrast, can be permitted and built in two to four years. Delaying renewable energy additions ten years greatly increases costs and deprives customers and the public of their price stability, avoided fossil fuel consumption and environmental benefits.

Proactive development allows approval of new transmission before all of the generating projects necessary to utilize the full capacity of the transmission have been built. This creates the risk that the transmission built may not be fully utilized. Proactive policy must balance economic risks to transmission developers against risk to consumers. To minimize these risks, states can link proactive transmission approvals to renewable energy zones. Policies that cluster renewable energy development in zones increase the likelihood that transmission built to such zones will be fully utilized.

Smart From the Start Planning

A crucial first step in planning infrastructure projects is to avoid areas where development is prohibited or constrained and environmental conflicts make litigation or other delays in permit approval likely. Early stakeholder involvement in recent project planning has warned developers away from such areas, saving time and money.

After avoiding no-go areas, generation and transmission project siting faces other environmental sensitivities, on both public and private lands. More complete wildlife and species databases and Geographic Information Systems (GIS) mapping tools now make it possible to plan large infrastructure projects with unprecedented levels of knowledge about environmental impacts. Smart from the Start planning takes advantage of this information to minimize environmental and cultural conflicts. Stakeholders are often the best sources of such information and are crucial for incorporating it into project plans.

The Environmental Data Task Force (EDTF) formed by the Western Electricity Coordinating Council has developed a data-driven methodology for comparing project alternatives. This has institutionalized Smart From the Start Planning at WECC, and has thus established a standard for use by utilities, generation-transmission developers and state and federal agencies. The U.S. Department of the Interior and environmental NGOs now employ Smart From the Start planning principles.

Stakeholder Involvement

Transmission development is controversial everywhere. In order to be approved and built, transmission projects must increasingly earn public consent. Effective engagement of stakeholders as sources of data and perspective is essential to the development of successful plans.

Traditionally, transmission planning and generating siting has been done mainly by utilities and generating companies. Planning failures, population pressures and increasing environmental and cultural sensitivities now limit the effectiveness of utility-led approaches. State and federal agencies, counties, tribes, agricultural land consumer interests, new energy technology companies and environmental and public interest NGOs often have material interests in siting, permitting and operation of generation and transmission. This range of stakeholders has become increasingly knowledgeable about energy development and electric system operation. Planning benefits from engaging them.

The most effective way to speed transmission development is to improve the quality of transmission planning. The best plans, and the ones most likely to be approved, are those that are responsive to local, public and stakeholder concerns. Stakeholder involvement is crucial to the design of such plans. It can save years of development time by warning projects away from sensitive areas where development is likely to provoke strong opposition or litigation. Stakeholder support for development of facilities they have been involved in helping design greatly facilitates approval by decision-makers.

Public Interest Standards for Transmission Development.

Large infrastructure projects increasingly must earn public consent. Standards can help guide planning to address factors of most concern to the public. These include: security, job creation and economic development, public health and environmental impacts, including air quality, water consumption and emissions. These factors are rarely considered in transmission planning. In order to build public support for approval of needed transmission, state commissions can insist that diverse stakeholders be involved in planning, and can require transmission plans to demonstrate that they have considered issues of most concern to the public in their states.

Regional Coordination

At the beginning of 2010, with funding from the American Recovery and Reinvestment Act, the Western Electricity Coordinating Council (WECC) began development of the first-ever infrastructure plan covering the entire western US. This effort is intended to identify transmission needed under different scenarios for the future of the West. Transmission projects found to be needed under multiple scenarios will have a strong basis for being approved over the next several years, to be ready in time to meet western need in the period 2020-2030. In 2011, FERC Order 1000 gave added impetus to coordination of regional planning efforts.

WECC is conducting this planning with unprecedented levels of transparency and stakeholder involvement. The Scenario Planning Steering Group, the central body of the Regional Transmission Expansion Plan (RTEP) process, is made up of equal numbers of state representatives, utilities, and NGO stakeholders.

In order to develop the scenarios at the center of this process RTEP, in coordination with state officials organized as a State-Provincial Steering Committee, has become a forum for careful consideration of many of the resource procurement, system operation, market structure and transmission planning policies identified in this document. RTEP is also developing stakeholder-vetted assumptions about demand growth, technology cost and performance, environmental costs and other key parameters that can be applied consistently across all areas of the West.

As a result of this work, state decision-makers now have means to ensure that generation and transmission planning in their states employs this publicly-approved data and takes advantage of input from an open and transparent stakeholder engagement process. For investors performing due diligence on transmission projects, this more and better information has the potential to reduce both risks and costs.

4. Aligning Electric System and Environmental Goals

It is greatly in the public interest to better align power system operation with environmental and climate goals. This is a central goal of orderly transition to reliance on clean resources. State policies and regulation are essential to this task.

Emissions and Water Performance Standards

Standards in effect in some western states prohibit or restrict procurement of power that has emissions greater than a target threshold, generally the emissions of a modern gas turbine. Emission Performance Standards (EPS) encourage retirement of the oldest and dirtiest generation. This improves the overall energy efficiency of the generating fleet, and so reduces operating costs. It creates material public health, air quality and carbon benefits. As with building and appliance efficiency standards, EPS help stimulate continuous innovation — in this case, in generation technologies — and drive investment in clean resources.

Oregon and California have emissions performance policies in place. They are described in Section 6, Best Practices.

Water Performance Standards.

Thermal power plants consume huge amounts of water. Plants in the six states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming consume more water each year than the cities of Albuquerque, Denver and Phoenix combined. Climate projections anticipate persistent drought periods for these states in coming decades. With water supply at critical levels in much of the West, coal, gas and nuclear plants increasingly have to compete for water with cities and agriculture. This competition makes it appropriate for regulators to direct resource procurement to consider power plant water withdrawal and consumption as planning criteria.

Public Health and Ecological Impact Policies

Minimizing the impacts of production and consumption of energy is key. Using less energy and utilizing resources that emit few toxics, have very low emissions and use little water can produce major public health and ecosystem benefits. The impact of clean generation on lands, habitat and species must be carefully managed as utilization of wind and solar generation increases to replace coal and gas. Regulators can take all of these actions:

- Recognize public health and ecosystem costs and benefits inherent in public and private utility decisions to apply these currently "external" costs as critical components "internal" to all utility decision making.
- Apply public health statistics to utility investment decisions that determine the kinds, numbers, and trends of public health impacts.

- Develop and apply metrics that determine how and to what extent utility investment decisions impact public and private health costs.
- Account for carbon liabilities by including a carbon price in procurement planning.
- Build mitigation measures for extreme weather events and other climate disruption effects into utility operations and procurement planning.
- Ensure ecosystem impacts are considered in utility decision making. Support data collection to improve understanding of ecological impacts of energy development and use. Avoid areas where development is prohibited or constrained and environmental conflicts make litigation or other delays in permit approval likely. Work to align least economic cost with least environmental cost in all aspects of electric system operation.

5. Economic Development Policies

Electricity infrastructure investment choices have enormous consequences for job creation, local and state economic development and industrial competitiveness. Some state statutes prohibit regulators from basing procurement approvals on any factors other than reliability and cost. But regulators also have a responsibility to make decisions in the best long-term interests of their states and of customers who are also citizens. Policies that support transition to a clean energy economy include:

- Recognize roles that investors and publicly owned utilities can play in building jobs and economic development across the West by pursuing an orderly transition to clean energy.
- Structure energy efficiency, demand management, and distributed generation programs to create jobs and local economic development.
- Realize that renewable energy investments substitute capital for fuel. The substitution has profound impacts on consumers' long term costs, risks, and liabilities that directly affect local business and investment climate.
- Parallel demand side efforts with economic development policies that build on investments in manufacturing, installation and operations for clean energy production at the bulk power level in solar, wind, geothermal, and transmission facilities.
- Quantify and apply job creation data in both public and private sector utility decisions, including employment levels, compensation, training, and duration.
- Monitor utility investment and public approval decisions against criteria for economic impacts, including income, investment for returns, taxes generated, and duration of dollar circulation in local economies.
- Develop and apply metrics for economic opportunities in utility investment decisions, including business creation and relocations, investment attraction, and sustained orderly development of clean energy technologies, services, and firms.

6. Best Practices

Examples of some of the policies outlined above illustrate best practices now in effect in western states.

Integrated Resource Planning, Best Practices: Northwest Power and Conservation Council 6th Plan (2010)

The Northwest has a strong history of integrated resource planning that includes all resource options, including energy efficiency and demand-side management. The Northwest Power and Conservation Council was created by an interstate compact in 1981, after inaccurate load projections led to the mistaken perception of impending power shortages. This perception fueled over-investments in nuclear power that led to the largest municipal default in the nation's history.

Every five years, the Council develops a power plan that provides important guidance to the region's utilities about what resource and transmission options are least-cost and least-risk. The Council's Sixth Power Plan of 2010 projects that 80% of the region's load growth can be cost-effectively met with energy efficiency and conservation.[3] As a result, all of the region's utility IRPs have robust energy efficiency and conservation targets, especially PacifiCorp's most recent 2008 IRP, which factored in the risk of future CO_2 cost adders.

The Northwest Power Planning and Conservation Act of 1980 defined resource cost-effectiveness in a way that facilitates energy efficiency savings being considered as a resource equivalent to generating resources.[4] This has helped translate planning targets established in the IRP into actual procurement decisions.[5] NPPC plans set a standard against which other planning efforts can be measured.

Energy Efficiency, Best Practices: Arizona Energy Efficiency Resource Standard

Arizona's Energy Efficiency Resource Standard for electricity was established in 2009.[6] It sets targets of 2% annual savings in electricity statewide, beginning in 2014, and 22%

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[3] http://www.nwcouncil.org/energy/powerplan/6/default.htm

[4] The Power Act's definition states that: "cost-effective," when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof. Northwest Power Act, supra note 1, at §3(4)(A)(ii), 94 Stat. 2698.

[5] Tom Eckman, Manager of Conservation Resources for the Northwest Power and Conservation Council, provides an excellent explanation of the issues involve in treating energy efficiency as a resource in his paper, "Some Thoughts on Treating Energy Efficiency as a Resource," ElectricityPolicy.com, 2011.

[6] Docket No. RE-00000C-09-0427; Decision No. 71436.

cumulative savings in the amount of electricity needed to meet demand in the state by 2020. The rule has performance incentives to spur achievement.

This 22% savings target is the highest among western states. Nationally, Arizona's savings goal is exceeded only by Vermont (27% savings by 2020), Maryland, New York, Massachusetts and Rhode Island.

A helpful guide to state energy efficiency policies is available from the American Council for An Energy Efficient Economy: "Energy Efficiency Resource Standards: A Progress Report on State Experience," June 2011. This report summarizes all state energy efficiency policies. For programs in effect for longer than two years, the report reviews the legislative and regulatory background of the policy; savings achieved versus program targets; factors affecting performance; program design; funding levels; and performance incentives. The report also has practical recommendations for continuous expansion of energy efficiency savings.

Emissions Performance Standards, Best Practices: Oregon Energy Facility Siting Council Law and Rules

The Oregon carbon dioxide (CO2) siting standard is the first of its kind in the U.S. Adopted by the legislature in 1997, this standard requires carbon dioxide emissions from all new natural gas power plants to be less than 0.675 lb. CO2/kilowatt-hour (kWh). This was about 17% below the industry norm at the time. The standard can also be met with cogeneration. Proposed plants that don't meet the operational standard may still be approved by providing an alternative compliance payment to the Oregon Climate Trust, which invests the funds in carbon sequestration, renewable energy or other carbon offset projects.[7]

Emissions Performance Standards, Best Practices: California Greenhouse Gas Performance Standard

California imports approximately 20% of its electricity, with most of that from coal units. Importing additional coal would make meeting the requirements of California's greenhouse-gas reduction law, AB32, impossible.

Accordingly, in 2006 the California legislature enacted a law, SB 1368, prohibiting power buyers in the state from signing contracts longer than five years for sources that emit any more than 1,100 pounds of CO2 per megawatt-hour (MWh). This limit reflects the efficiency level of older gas-fired generators (approximately 10,000 BTU/kWh). It effectively prohibits new contracts for coal power, which has average emissions of 2,000 pounds of CO2/MWh. This standard has focused power procurement on cleaner, more efficient supply sources.[8]

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[7] http://cms.oregon.egov.com/energy/Siting/Pages/standards.aspx#Carbon_Dioxide_Emissions

[8] California Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) was signed into law by Governor Arnold Schwarzenegger on September 29, 2006. California Energy Commission regulations implementing this bill are available at: http://www.energy.ca.gov/emission_standards/

Renewable Energy Development Zones, Best Practices:

Six western states have conducted public processes to locate their best renewable resource areas. These processes are aimed at aiding site transmission, promoting renewable energy resource development, identifying risks to wildlife and special lands, and creating economic development opportunities. Two of these have set new standards for planning renewable energy development: California's Renewable Energy Transmission Initiative (RETI); and the Western Governor's Western Renewable Energy Zone Initiative, WREZ.

California's Renewable Energy Transmission Initiative (RETI)

RETI's mission was to develop a statewide transmission plan capable of accessing and delivering sufficient renewable energy to meet state policy goals and able to win broad stakeholder support. It operated as a collaborative, and was led by a 29-member Stakeholder Steering committee made up of representatives of California Load-Serving Entities (LSE) and Transmission Providers; biomass, geothermal, solar and wind generating companies; local, state and federal permitting agencies; the military; tribes; consumers; and environmental groups.

RETI estimated the cost of developing renewable resources throughout California and neighboring areas and transmitting the energy to California consumers, utilizing both existing and new transmission infrastructure. It ranked Competitive Renewable Energy Zones (CREZ) by the levelized cost of energy that could be produced in them. RETI also assessed potential environmental concerns associated with CREZ, the renewable energy development areas within them, buffer zones around them, and the footprint of associated transmission facilities. RETI then combined economic and environmental rankings to identify CREZ most likely to be developed and thus best able to justify transmission to those areas.

RETI developed an objective methodology for estimating the relative usefulness of proposed transmission components for carrying renewable energy. This provides significant new information about the type of generation that may flow on proposed transmission facilities and is of great interest to regulators, utilities and many public stakeholders. RETI used this information to compile a conceptual transmission plan capable of accessing and delivering sufficient renewable energy to meet state goals. This conceptual plan has been turned over to the California Independent System Operator and Publicly Owned Utilities for detailed study.[9]

Western Renewable Energy Zones (WREZ)

In 2008 the Western Governors' Association (WGA) launched the Western Renewable Energy Zone (WREZ) initiative. This applied Texas' Competitive Renewable Energy Zone model to the Western grid region. The Texas legislature ordered the Texas Public Utilities Commission (TPUC) to identify renewable energy resource zones for development and to trigger the transmission projects needed to serve them. With

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[9] http://www.energy.ca.gov/reti/

planning and study support from the Electric Reliability Council of Texas (ERCOT), the TPUC wrote rules and set up decision-making dockets that led to commitments to invest billions of dollars in transmission to serve more than 10,000 MW of new wind plants. These projects will save money for Texas electricity consumers as wind replaces higher-cost natural gas generation.

WREZ is a four-part project, funded by U.S. Department of Energy (DOE). The first two phases:

- Mapped high-quality renewable energy zones
- Produced renewable resource supply curves for each zone
- Developed a publicly available model to estimate the delivered price of power from renewable energy zones to load centers
- Performed screening analysis on the sensitivity of least-cost WREZ resource selection, associated transmission, and costs for meeting aggressive West-wide renewable energy targets under various assumptions
- Developed conceptual transmission plans through the WECC planning process

The WREZ phase 1 report[10] identifies renewable energy zones and outlines the agreements among a diverse group of stakeholders on legal or policy mandates to exclude development. The report also documents the inability of some stakeholders, particularly state wildlife agencies, to adequately identify and map areas of potential concern, as well as the lack of sufficient scientific information about those concerns.

The Regional Transmission Expansion Plan process now underway at the Western Electricity Coordinating Council (WECC) will build on WREZ planning work to identify transmission infrastructure necessary to access and deliver renewable energy likely to be needed across the region in 2030.

Coal Transition, Best Practices: Colorado, Oregon and Washington Plant Retirement Agreements

Denver Metro Area Coal Plants, Denver, Colorado

In December 2010, in line with the Clean Air, Clean Jobs Act passed by the Colorado Legislature, the Colorado Public Utilities Commission ordered 902 MW of coal capacity to be retired, including all the coal plants in the Denver metropolitan area. Some of this coal capacity is being replaced with gas-fired generation. The remainder is being replaced with synchronous condensers to provide local voltage support, without emissions.[11]

Boardman Coal Plant, Boardman, Oregon

[10] http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=5&Itemid=

[11] http://www.dora.state.co.us/puc/rulemaking/HB10-1365/HB10-1365.htm

The Boardman coal plant was authorized in 1975, two years before the 1977 Clean Air Act amendments, which would have required the plant to meet stricter emission standards. The plant accounts for 65% of stationary SO_2 emissions, 35% of NOx emissions, and 7% of CO_2 emissions in Oregon. Portland General Electric originally planned to operate the plant until 2040. To do so, it would have to install approximately $500 million of pollution control equipment on the plant by 2017 in order to comply with federal and state clean air standards. In April 2011, PGE reached an agreement with environmental and public interest groups and regulators to close the plant in 2024. This will save $470 million in upgrades they would have been required to install had they kept the plant operating until 2040. The retirement plan worked out by the parties ensures orderly transition away from coal for Oregon citizens.

Centralia Coal Plant, Centralia, Washington

The plant's two identical coal-fired generating units have a combined capacity of 1,340 MW. They were placed in service in 1972 and 1973. Coal for the plant is delivered by rail from Montana and Wyoming. The plant burns the contents of nine 110-car coal trains each week. It is the largest single source of greenhouse gas emissions in the state. It also emits 350 pounds of mercury annually, making it the state's largest single source of mercury pollution. Mercury is a bio-cumulative neurotoxin which causes brain damage in humans and is especially dangerous for children and pregnant or nursing mothers. In early 2011, Environmental organizations reached an agreement with plant owner TransAlta to retire the plant in 2025.