FUTURE ELECTRICAL ENERGY RESOURCES

for

LOS ALAMOS COUNTY

Report of the

FUTURE ENERGY RESOURCES COMMITTEE

Members: Joan Ahlers, Edward Birnbaum, Robert Gibson (chair), Donald Machen, Grant Stewart, Kathleen Taylor, Craig Wehner

to the

LOS ALAMOS COUNTY

BOARD OF PUBLIC UTILITIES

7 July 2015

EXECUTIVE SUMMARY

The electric power industry is changing dramatically to reduce its emissions of carbon dioxide and other "greenhouse" gases that are major contributors to global climate change. In concert, the Los Alamos County (LAC) Board of Public Utilities (BPU) established in 2013 a goal for LAC's Dept. of Public Utilities "to be a carbon neutral electric provider by 2040." To assist it in reaching that goal, BPU formed a "Future Energy Resources Committee" (FER) to: (1) "examine and recommend a definition of carbon neutrality for the County," (2) "study and recommend future renewable energy generation resources," and (3) "study and recommend policy toward distributed generation in the County."

Definition. FER recommends that by 2040 electricity distributed to LA County consumers (exclusive of DOE/LANL) be generated or purchased from sources that do not cause any significant net release of carbon dioxide, methane, or other greenhouse gases.

Future Electric Generation Resources. FER expects the County's annual electrical energy load by 2040 to be similar to today's 125,000 mega-watt hours. A number of factors could drive it either direction, but it will most likely remain within ±20% of the current load.

LAC and DOE/LANL pool most electric generating resources through an Energy Coordination Agreement which expires in 2025. FER recommends that any subsequent pooling not dilute carbon-free LAC power, particularly the output of the County-owned Abiquiu and El Vado hydroelectric plants. These historically have provided more than half the electricity LAC needs, although their output varies considerably and will decline if drought conditions persist.

FER recommends LAC divest coal-burning generating assets, i.e., its ownership share in the San Juan Generating Station and, if feasible, its "life-of-plant" power purchase agreement at the Laramie River Station. Some combination of three types of sources could provide replacement base power: (1) nuclear, (2) local firm photovoltaic (PV), and (3) market purchases, depending on their availability, reliability, and cost. To be practical, PV must ultimately be firmed by some kind of energy storage, most likely batteries or pumped hydroelectric.

Distributed Energy Resource Policy. Solar PV arrays on individual residential and institutional "rooftops," the most visible component of "distributed energy resources" (DER's), are rapidly growing in popularity. The economic value of PV in Los Alamos today is primarily in daytime "peak-shaving." PV-produced power would be more valuable if it were firmed and even dispatchable so it could be accessed by the utility to benefit all customers when most needed. Policies and rates should favor firm and dispatchable energy.

FER recommends development of engineering-based policies to safely and most beneficially integrate DER's into the electric power distribution system. The rate structures should separate consumption and generation rather than mixed as in net metering for DER energy producers. Rates should fairly allocate the cost of maintaining the distribution system, recognize that electricity has different values at different times, and promote the value of firm solar energy in moving LAC towards zero carbon emissions.

TABLE OF CONTENTS

1. Introduction: Context and Motivation

1.1. Carbon, Climate Change, and Utility Industry Transformation

The effect of human activity on the global climate is well established. "There are still some uncertainties, and there always will be in understanding a complex system like Earth's climate. Nevertheless, there is a strong, credible body of evidence, based on multiple lines of research, documenting that climate is changing and that these changes are in large part caused by human activities. While much remains to be learned, the core phenomenon, scientific questions, and hypotheses have been examined thoroughly and have stood firm in the face of serious scientific debate and careful evaluation of alternative explanations."[1]

Global climate change is not a theory for the future. It is already happening. It manifests itself in elevation of the Earth's temperature ("global warming"), shifts in precipitation patterns; rise in sea levels, and more frequent weather extremes.

The principal cause of climate change is increased concentrations in the atmosphere of "greenhouse" gases produced by human activity since the beginning of the industrial age two centuries ago. Carbon dioxide, CO_2, is the principal contributor. Along with water, it is a fundamental byproduct of combustion of hydrocarbon compounds, the main constituents of most of our primary energy sources: coal, wood, natural gas, and petroleum fuels. Methane (CH_4), the main component of natural gas and a byproduct of petroleum fuel production and other industrial and agricultural processes, is also a major greenhouse gas. (In the present context, hydrocarbon fuels, CO_2, and CH_4 are all referred to as "carbon" and their absence as "carbon-free." These carbon fuels, largely from ancient plant and animal matter, are also often called "fossil" fuels.)

Electrical energy production for Los Alamos County, not including LANL, causes an average of 83,000 metric tons of CO_2 to be emitted into the atmosphere each year mostly due to the burning of coal at the San Juan and Laramie River plants. That is more than 40% of Los Alamos County's (LAC's) total energy "carbon footprint" the balance being roughly equally divided between combustion of natural gas for heating and petroleum motor vehicle fuels.

The harmful effects of climate change are prompting major changes in the utility industry, which has heretofore been remarkably stable for the past century. Electric utilities, long reliant primarily on coal-fired steam power plants, are moving towards electrical energy sources that do not produce greenhouse gases. Hydroelectric and nuclear power have long been significant sources of carbon-free electricity. Wind, solar, geothermal, and tidal energy are being increasingly harnessed to produce electric power. Their contributions remain small, but are growing very rapidly.

1.2. BPU Carbon Neutrality Goal

In recognition of the need to move away from CO_2-producing electrical energy sources, the LAC Board of Public Utilities (BPU, or "the Board") adopted, on September 18, 2013, the strategic goal for the Department of Public Utilities (DPU) for County Fiscal Year 2015 (FY15) to "be a carbon neutral electric provider by 2040" as part of its broader strategic objective to "achieve environmental sustainability." That goal was effectively confirmed by its inclusion in BPU's goals for DPU adopted on December 18, 2013. It was again affirmed by BPU on October 15, 2014, by inclusion in its goals for DPU for FY16. As part of that action, BPU also established a short-term goal for DPU for FY16 to "develop a plan to deal with the effects of distributed generation on electric power production, specifically incorporating the downward trending cost of renewable energy resources."

1.3. FER Committee Charge

To assist BPU and DPU in pursuit of these goals, the Board on January 21, 2015, established an ad hoc citizen "Future Energy Resources Committee" (FER or "the Committee"). As stated by the Board, "The purpose of the Committee is to examine and recommend a definition of carbon neutrality for the County, study and recommend future renewable energy generation resources, and study and recommend policy toward distributed generation in the County." Seven Los Alamos citizens were appointed to the Committee on February 17, 2015, and directed to present their (sic) findings and recommendations to the Board at its July, 2015, meeting."

BPU's charge to FER specifically includes "future renewable energy generation resources." BPU later clarified that guidance to be limited to electricity. It does not include natural gas, also supplied by DPU, which also produces prodigious quantities of CO_2 upon combustion.

It is not possible to consider only renewable resources without considering all resources, both carbon-based and carbon-free. Evolution from the former to the latter is desired and anticipated. While nuclear power is technically not a renewable resource, it is CH-free and is considered as equivalent in this study.

"Distributed generation" is understood to mean solar photovoltaic (PV), at least for the foreseeable future. Firming of energy produced by PV is key to its real value, so it is considered along with generation itself. Generation, storage, and power conversion and control equipment (i.e., inverters) are collectively "distributed energy resources (DER)." This study considers that slightly broader scope.

1.4. Caveats in Study

As noted above, the electric power industry is becoming more dynamic. Its technology, statutory/regulatory (i.e., political) environment, and economics are changing. Quantitative predictions are only possible for the next decade at best. Hence FER focused on principles, trends, possibilities, and options to guide decision-making. The topic will require increasingly frequent, if not continuous, revisitation, as is typical of most businesses.

1.5. LA County's Electric Utility Relationship to DOE/LANL (ECA)

Since 1985, LAC and the Department of Energy's Los Alamos National Laboratory (DOE/LANL or LANL) have pooled their electrical generating resources under an "Energy Coordination Agreement" (ECA or "Pool"). The ECA was recently extended from its original

2015 expiration until 2025. Under this agreement, most electrical power resources of both LAC and DOE/LANL are treated as common assets with their power output distributed to the two entities in accordance with their respective needs. Traditionally, DOE/LANL has consumed about 80% of the total energy produced or purchased by the ECA Pool. The hourly demand pattern differs for the two entities.

FER has interpreted BPU's goal and the Committee's charge to apply only to non-DOE/LANL electricity consumption and resources in LA County. Future DOE/LANL policy and direction may provide further advantages to resource cooperation in some form after 2025, but those cannot presently be predicted.[2]

2. The Goal: Carbon Neutrality

2.1. Definition

Clearly, the ideal end state would be for LAC's electrical power sources to produce no greenhouse gases. That appears to be technically and economically achievable by 2040 or perhaps sooner. Hence, FER recommends the following definition of carbon neutral for LA County:

Electricity distributed to LA County consumers shall be generated or purchased from sources that do not cause any significant net release of carbon dioxide, methane, or other greenhouse gases.

"LA County consumers" does not necessarily include DOE/LANL. It is bound by the Energy Independence and Security Act (EISA) and executive orders to reduce carbon generation at least into the mid-2020's but does not currently have a net-zero carbon emissions goal.

While actual generation should not produce any greenhouse gases, generating facilities are likely to emit such gases or other undesirable by-products during their construction. These should be minimized.

Occasional production (e.g., emergency generators) or purchases of carbon-based electricity when carbon-free supplies are not practically available may be necessary. These supplies are expected to be offset (e.g., via Renewable Energy Credits from previous sales of surplus carbon-zero electricity) to maintain overall net zero carbon-based electricity supply.

2.2. Relationship to Reliability and Cost

Electricity consumers and suppliers have historically focused on two major factors in power supply: reliability and cost. There have always been trade-offs between the two criteria. Environmental impact, principally greenhouse gas production, should become a third criterion.

The natural phenomena upon which most carbon-free power depends are more variable than carbon-based generation. Patterns are sometimes predictable, sometimes not. The wind sometimes blows, sometimes not. The sun shines only during the day; even then, solar insolation varies with cloud cover. This source variability adds another dimension to the transmission and distribution system reliability that has long been a goal of utilities and expectation of customers. LA consumers should not have to expect any reduced delivery reliability or power quality. Source availability and power quality should be at lease comparable to that of carbon-burning plants (which are not available even close to 100% of the time). It is important to recognize that costs of the carbon-free power are declining while those for carbon-based power are increasing.

The LA County Charter, in Sec. 504, requires that utility "rates and charges shall be just, reasonable, and comparable to those in neighboring communities and shall be uniform for all consumers of the same class." The requirement that rates be "comparable to those in neighboring communities" sets a loose cap on any major cost increases for carbon-free power until neighboring communities also move in that direction.

Bi-annual DPU surveys from 2005 through 2013 (the 2015 survey is in progress) indicate a majority of DPU customers consider renewable energy to be important and are willing to pay up to 15% more for it. The surveys did not ask how many would pay an even higher incremental amount[3] but they indicate an appreciation by CPU customers of the value of carbon-free power.

3. Load Projections

Electrical loads are measured both instantaneously, which is power, and integrated over time, which is energy. Power supply systems must have capacity to meet peak power demand. Otherwise, voltages fall and can ultimately affect devices at the point of use ("brownouts").

Unless otherwise indicated, electrical power is expressed in this report in megawatts (MW, one million watts) and electrical energy in megawatt-hours (MWh, a megawatt for one hour). Individual customers will normally have loads of a few kilowatts (KW, or thousand watts). Their electric meters read and billings are based on energy use measured in kilowatt-hours (KWh, a kilowatt for one hour).

3.1. Historical LAC Load

Electrical load for the non-LANL portion of LA County rose by 1-2% / yr. until a decade ago and has been quite stable since. Energy consumed by month and year for 2000 – 2014 is shown in Figs. 1 and 2, respectively.[4] Annual energy use is typically 120,000 – 125,000 MWh / yr. Close examination of Fig. 1 shows a consistent seasonal variation. Use is slightly higher during winter (11,000 – 12,000 MWh / mo. in December and January) and summer (10,000 – 11,000 MWh / mo. June through August) than in spring and fall (9,000 – 10,000 MWh / mo.). Summer demand is driven by water pumping and air conditioning. Winter demand peaks arise from additional lighting, electrical space heating, electronic entertainment, etc.

Power consumption varies markedly during a typical day; and patterns are quite different for LANL and non-LANL loads. Fig. 3 shows typical diurnal load patterns for LANL, LA County, and total. LANL loads typically peak during afternoons, when air conditioning and laboratory equipment use peak. LA County loads are entirely different, peaking in the evening when workers get home, turn on lights, cook, turn on home electronic equipment, etc. Fig. 4 shows that these loads vary some, but the general characteristic of evening peaks is consistent.

LA County's overnight base, or minimum, load is typically about 10 - 13 MW. It falls below 10 MW (to an absolute minimum of about 8.5 MW) only a handful of times in a year. Demand rises to a typical evening peak of 14 – 19 MW. It exceeds 20 MW, to an absolute maximum of about 23 MW) only a handful of times per year.

3.2. Potential Load Changes

Five major factors could affect LAC electrical energy demand over the next 25 years.

<u>More Efficient Use.</u> More efficient or effective use of electricity (conservation) would lower demand. Replacement of incandescent and fluorescent lighting with light-emitting diode (LED) lamps is one example. Solar hot water heating (vs. electrical or gas) is another. While reductions in use up to ~50% are possible with concerted effort, 10-20% is probably more realistic.

<u>Distributed PV.</u> Solar photovoltaic (PV) panels owned (or leased) by individual property owners and mounted on rooftops or in back yards could reduce overall energy demand on DPU by perhaps as much as 20% or so. However, solar energy production peaks during the day and does nothing to reduce the evening peak demand unless it is accompanied by some form of energy storage or other firming mechanism. These issues are addressed in Sec. 5.

<u>Conversion of Natural Gas Heating.</u> LA County consumers burn roughly nine million therms (1 therm = 10,000 BTU's) of natural gas annually, releasing another 47,000 metric tons of CO_2 into the atmosphere. Most of this use is for space heating, with the balance for hot water heating, cooking, clothes drying, etc. The energy equivalent of a therm is 0.0293 MWh. Simply converting to electricity for all these heating needs would add more than 260,000 MWh to LAC's annual load – more than tripling it. A far more obvious and practical approach would encourage conversion to passive solar space heating and solar thermal hot water heating. This component of making LA's energy resources carbon neutral is beyond the scope of this study. But conversion, if it were to happen at all, would increase electrical demand.

<u>Population Increase.</u> Any increase in the County's population is likely to increase electricity demand more-or-less proportionately. Our population has been stable at ~18,000 people for the past 35 years. It is unlikely to grow more than 10%, if that, in the next 25 years.

Fig. 1. LAC Monthly Electricity Use

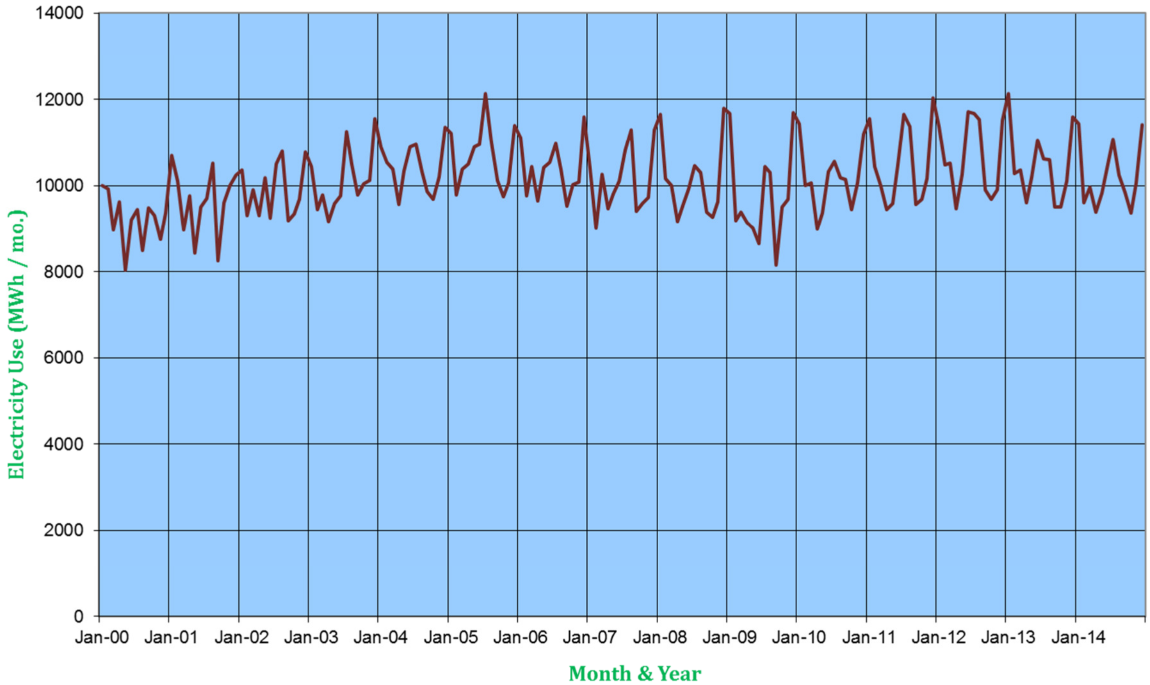


Fig. 2. LAC Annual Electricity Use & Sources

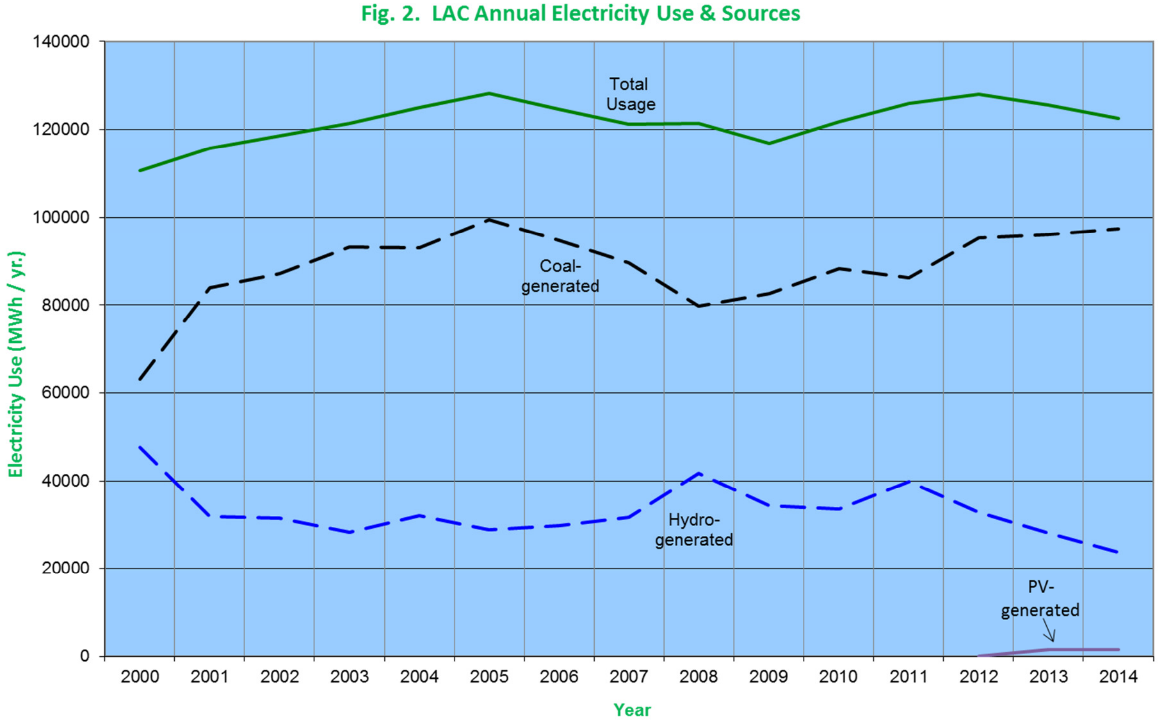


Fig. 3. Typical ECA Diurnal Load

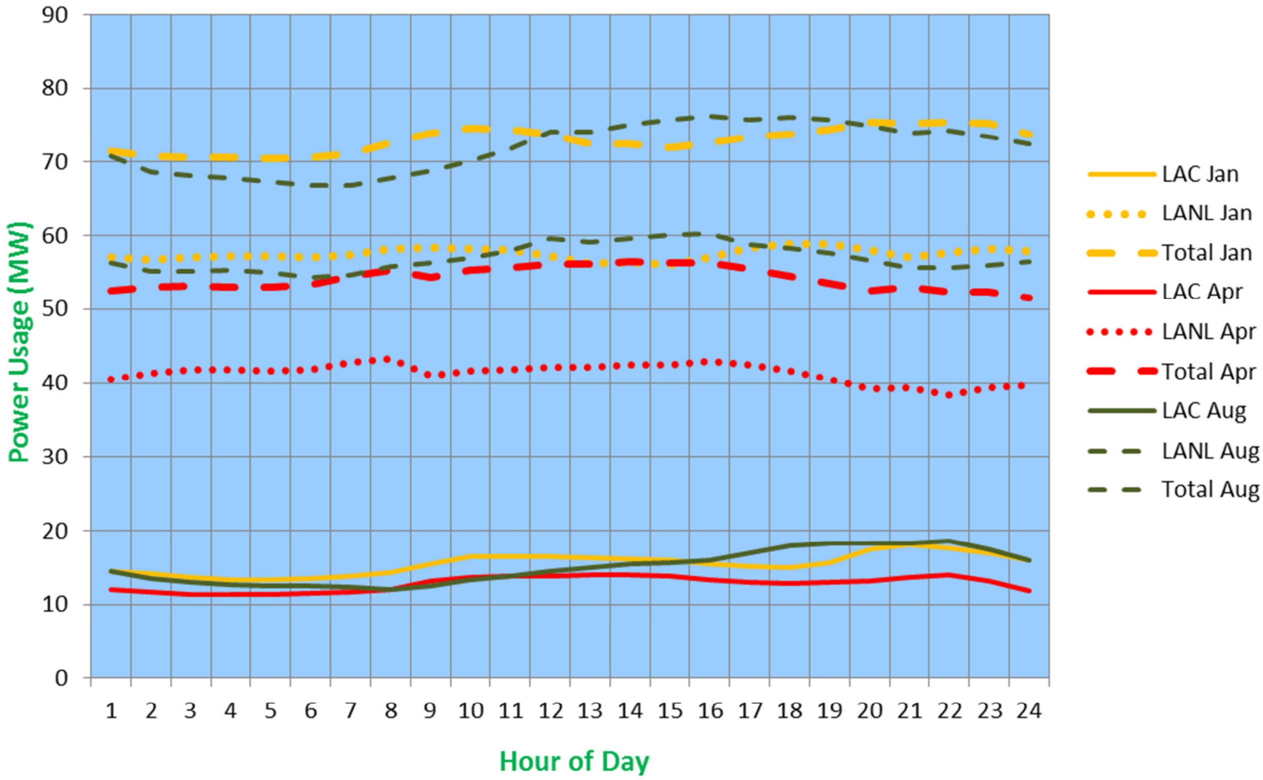
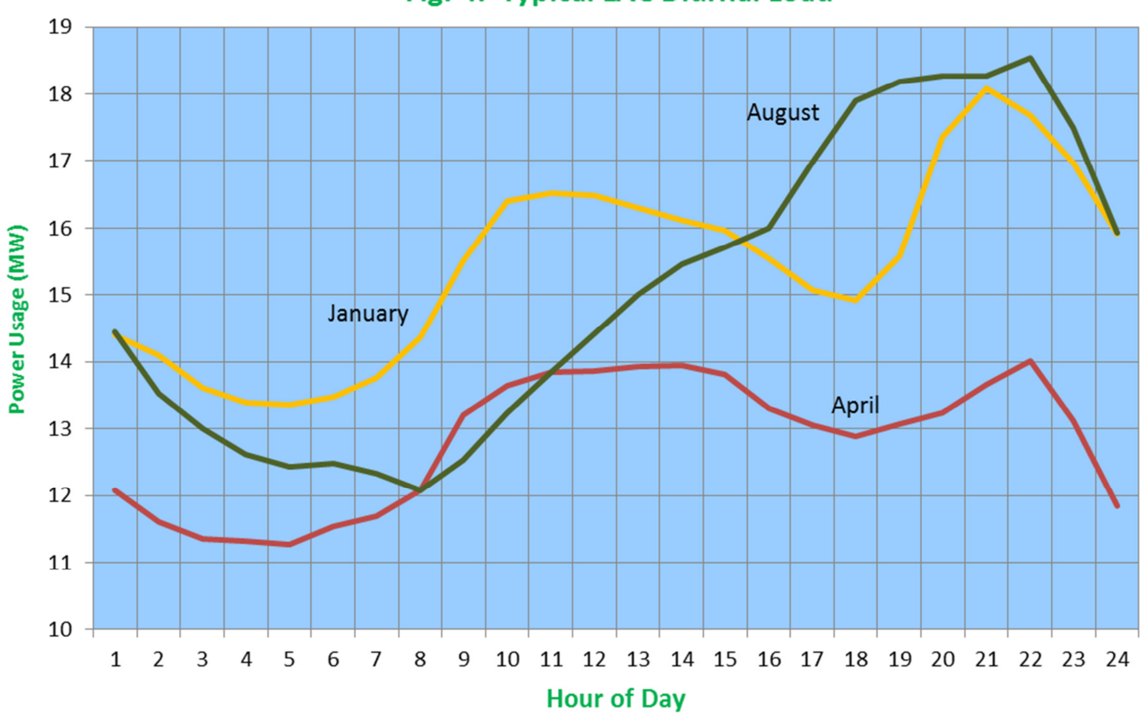


Fig. 4. Typical LAC Diurnal Load



Electric Vehicles. The largest potential increase in electrical energy use would be a transition to all-electric motor vehicles (EV's). Presently, an average (2006-14) of 6.3 million gallons of gasoline and diesel fuels are dispensed in LA County each year. Their combustion adds another 55,000 metric tons of CO_2 to the atmosphere annually. Conversion to electric vehicles would be environmentally beneficial (presuming carbon-free electrical power is available) and should be encouraged but would correspondingly increase electric load. There are many other issues outside the scope of this study. Relevant here is the roughly 44,000 MWh / yr. in additional electricity that could be needed.[a] This would be a "worst case" estimate from the electrical load standpoint although "best case" from the environmental perspective.

Barring an unlikely ban on internal combustion engine motor vehicles, EV penetration into the fleet is likely to be much less than 100%, even by 2040. And many EV's are likely to be charged from solar PV at their homes (or places of employment). Hence, the overall effect on utility electrical energy demand will be much less than the maximum. Just as important, most EV's could be charged when power is most available. Today, that is overnight. In the future it could still be overnight or it could be in the afternoon, if LA has a enough PV power available. EV batteries could also be shared with their "home base" building (residence or other) to provide significant storage beyond what might be installed there. EV's will certainly increase energy needs, but may be managed so as to have less effect on capacity requirements.

Overall Load Change Range. DPU currently estimates electrical load growth in the County at 1% / year, or about 1200 MWh / year, for the next decade. Looking towards 2040, it appears increases or decreases in energy load on DPU are equally likely and the load will still be in an annual range of 125,000 ± 25,000 MWh by then. That would be a maximum compounded average rate of change of 0.7%. The most likely scenario is that total demand on the utility in 2040 will not be much different than today's, so current energy demand can serve as a baseline for planning with recognition that it may change either way by up to 20% or so. Seasonal and diurnal use patterns are likely to be similar to today's.

Potential Capacity Changes. The purpose of a "smart grid" is to more flexibly match demand with often-distributed and increasingly varied and variable supplies. Customers can be incentivized to use or produce power at the most beneficial times. Reducing peak demand is one obvious example. Methods are discussed in Sec. 5.

3.3. DOE/LANL Load

DOE/LANL consumed an average of 420,000 MWh / year over the period 2000-2014. There was more variation year-to-year than the County's load due largely to different run cycles at the energy-intensive Los Alamos Neutron Scattering Center (LANSCE). There was very little change over the long-term.

---

[a] Based on local gasoline sales and assuming a nominal 20 miles-per-gallon, approximately 126 million miles are driven in LA County annually. If driving patterns do not change and all vehicles were replaced by electrical drive vehicles at the current (and unlikely to improve dramatically) energy efficiency of 0.35 MWh / 1000 mi., 44,000 MWh of electricity would be needed annually to power a 100% electric vehicle fleet.

DOE/LANL's current forecast is for an average load increase of about 4% / yr. for the remaining years of the ECA. This forecast is based on potential LANL activities that may or may not materialize. It should be noted that LANL has historically predicted substantial overall load increases that have not materialized.

4. Resources

4.1. Present Resources – the ECA Pool

Generation resources owned or contracted to LAC DPU and DOE/LANL are described briefly here. Power produced by DOE/LANL resources is presently combined through the ECA to meet joint load needs. Overall, about 80% of the combined power goes to DOE/LANL and 20% to LA County customers.

4.1.1. LA County Hydroelectric

Abiquiu Dam. LAC DPU owns and operates a small, low-head hydroelectric plant at Abiquiu Dam on the Rio Chama. The dam itself is operated by the U. S. Army Corps of Engineers (CoE) which stores and releases water from the dam for flood control and irrigation. Power is generated from whatever water is released. It is "run-of-the-river" generation; power produced varies depending on CoE's needs. Released water can bypass the electric generators if power generation is not necessary. This contrasts with the output of dams whose primary purpose is power generation; they are operated to maintain steady electric power output.

The Abiquiu hydroelectric plant, built by LAC DPU and placed on-line in 1989 contains two 6.75 MW generators and a newer (2011) 3 MW Low Flow Turbine Generator (LFTG). The latter increases the peak capacity of the plant to 16.5 MW when water flows are high. More importantly, it can take advantage of low flows insufficient to turn the main generators.

The original plant was financed by 30-year utility revenue bonds which (after refinancing) were retired June 30, 2015, lowering the annual debt service cost considerably.

El Vado Dam. LAC DPU owns and operates a similar hydroelectric plant at El Vado Dam, also on the Rio Chama. It is operated by the U. S. Bureau of Reclamation, also on a "run-of-the-river" basis for water storage and flood control purposes.
The El Vado hydroelectric plant was also built by LAC DPU in the late 1980's and contains a single 8 MW generator. That generator was shut down in late 2013 and is being rewound. Other major maintenance is being performed simultaneously. It should return to service later in 2015. The El Vado plant was financed with the same bonds as the original Abiquiu plant that are now retired.

WAPA. LAC also is entitled to purchase 1 MW of hydroelectric power from the Western Area Power Administration (WAPA). This power comes from large hydroelectric power dams throughout the West. It is firm, steady power year-round and year-to-year. However, the drought of the past decade has reduced reservoir storage levels to historic lows. If drought conditions do not improve, WAPA may not be able to deliver the full 1 MW contracted amount.

Total LAC Hydroelectric Resources. Combined, LAC's three hydroelectric resources have historically produced an average of about 70,000 MWh / yr. Seasonal variations are predictable. Output peaks in spring and early summer, declines in the fall, and is low during the winter. See Fig. 5. The annual amount has varied from a low of about 40,000 MWh in 2003 to a high of 100,000 MWh in 2008, as shown in Fig. 6.

Hydroelectric power production is renewable and emits no CO_2. All LAC DPU hydroelectric resources except the LFTG were in service before 2005 and hence do not create Renewable Energy Credits (REC's).

One potential impact of climate change is continued reduced precipitation in the Southwestern U.S. That could reduce output of all hydroelectric resources from historical levels and should be considered in planning.

4.1.2. LA County Coal-fired

Coal-fired steam has long been the generating backbone of the U.S. electric power industry. It has traditionally been the least expensive source. It is also the "dirtiest." Its flue gases contain large amounts of particulate, NO_x, mercury, and other pollutants. These can be greatly reduced by various filtering and precipitation processes. That is a major purpose of the environmental upgrades mentioned below. But combustion of any hydrocarbon intrinsically produces CO_2, which cannot be easily removed. For coal in this area, each megawatt-hour of electricity produced is accompanied by release of 915 kg (nearly a metric ton) of CO_2. For this reason, coal-fired power plants are "rapidly" (which is decades in utility system-speak) becoming "dinosaurs" in the U.S.

LA County has significant interest in two coal-fired power plants.

San Juan Generating Station (SJGS). This coal-fired steam plant near Farmington, NM, was built around 1980. LAC DPU owns 7.2% of the 507 MW Unit 4 providing a maximum net capacity to LAC of 36 MW. The operator and biggest owner is Public Service Company of New Mexico (PNM). LAC's share of the plant was also purchased with utility revenue bonds in 1985 which ultimately retired this year.

SJGS has required numerous upgrades to meet rising environmental standards. LAC's share of those costs has been paid through additional bonds, which retire in 2022 coincident with the end of the County's ownership commitment. Present wholesale cost of SJGS energy averages about $55 / MWh, including the upgrade debt service. There is doubt about how much longer after that the plant will continue to operate. (See. Sec. 4.3.2.)

Fig.5. LAC Hydroelectric Monthly Power Production

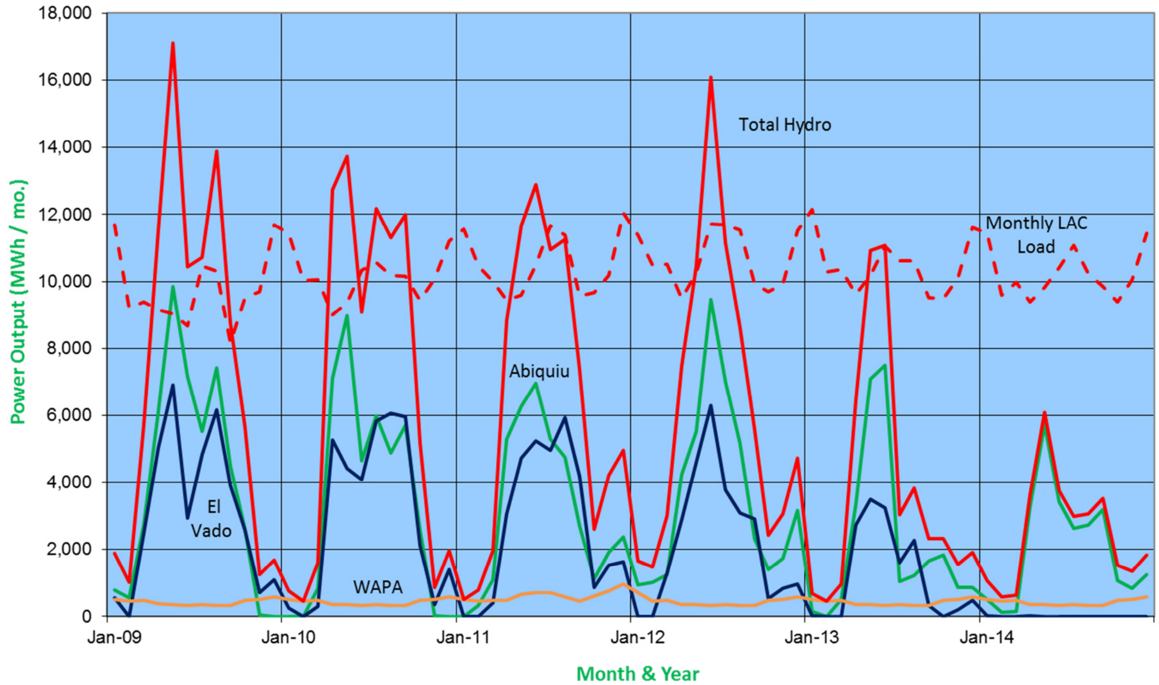
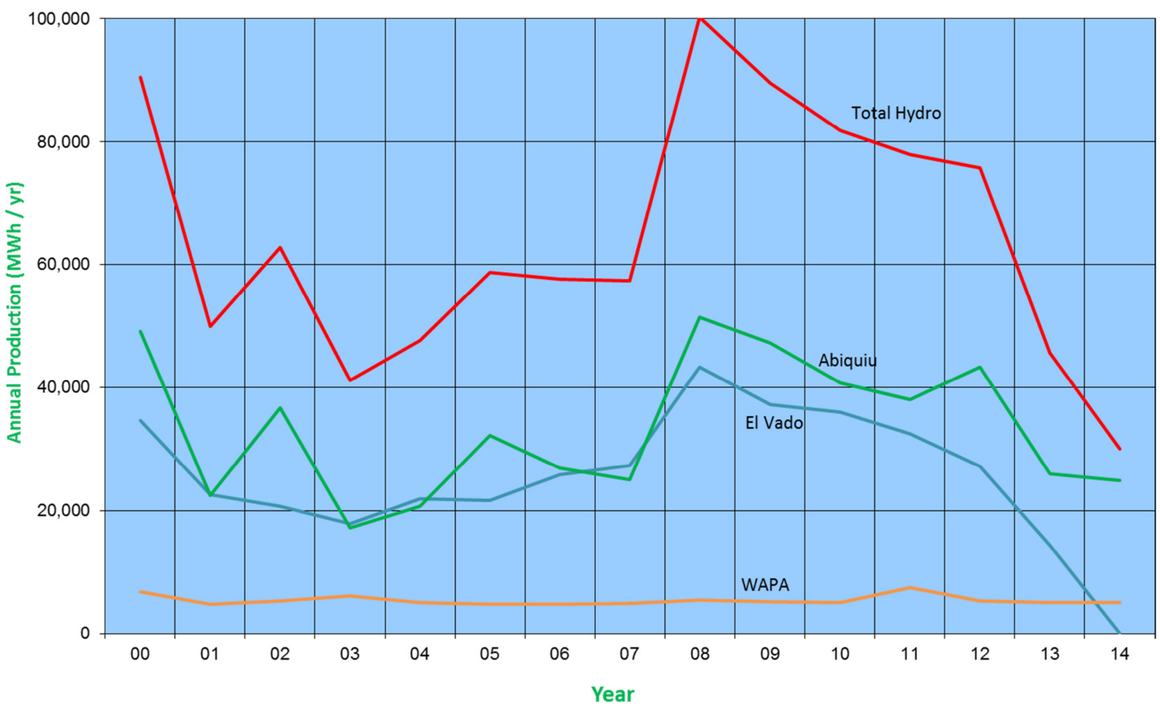


Fig. 6. Annual Hydroelectric Power Production



Laramie River Station (LRS). LAC DPU has a "life-of-plant" purchase power agreement for 10 MW from LRS, near Wheatland, WY, through one of its co-owners, Lincoln (NE) Electric Co. This coal-fired steam plant was built in the early 1980's and is projected to remain in service until ~2040. Debt service for the owners ends in 2016, with concomitant significant reductions in power charges from that plant as well.

Presently projected cost of LRS power in the near future is about $27 / MWh. However, that cost can be expected to increase, as it did at SGJS, as expensive environmental upgrades will be required there as well. (See Sec. 4.3.3.)

Figure 7 shows the output of both SJGS and LRS over the past six years. There is clearly substantial variation in the so-called "firm" power available to import from these plants.

4.1.3. LA County Solar

A 1 MW (utility-scale) solar array accompanied by 7 MWh of battery storage was built at the old County landfill by the Japanese research consortium NEDO in 2011-12. After the research was completed, both array and batteries were transferred to LAC DPU. In CY13 and CY14, monthly output has varied between 64 and 178 MWh with a monthly and annual average of 130 and 1560 MWh, respectively. This variation is largely from operational and maintenance issues due to the R&D nature of the installation, not variations in solar insolation.

4.1.4. DOE/LANL

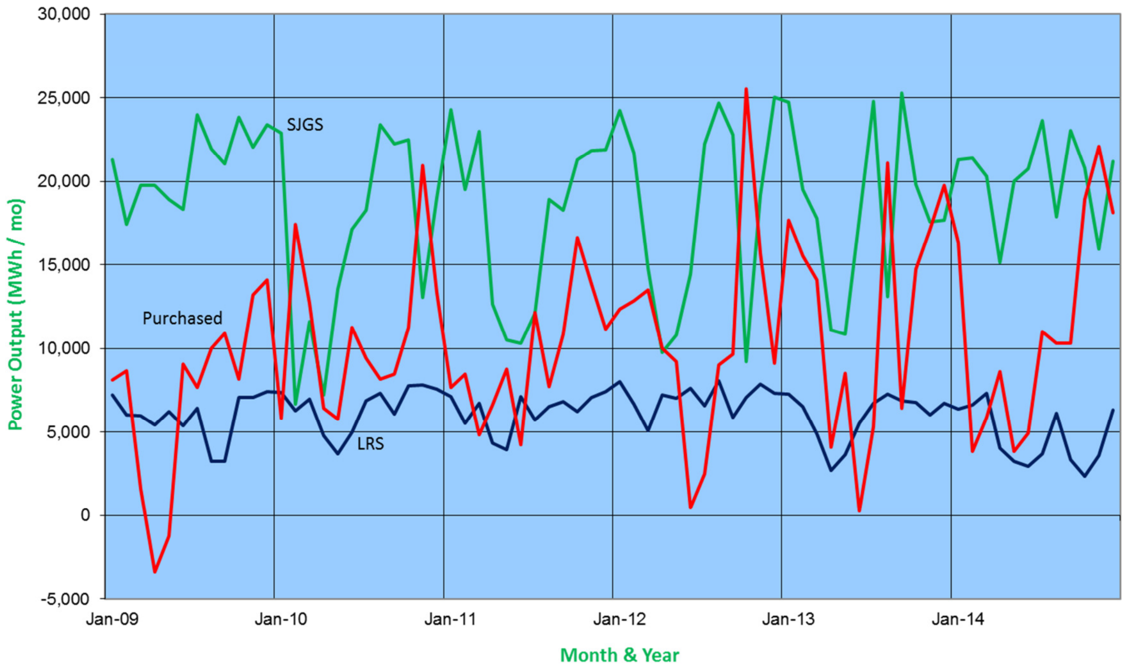
DOE/LANL has an entitlement to 11 MW of WAPA power.

LANL has two gas-fired generators at its TA-3 site, a 5 MW steam turbine and a 27 MW Combustion Gas Turbine Generator (CGTG). Both are very expensive to operate but provide local back-up and emergency power. LANL is in the process of reviewing all of its power generation needs and expects to replace some of these facilities with cleaner alternatives.

4.1.5. Purchased Power

The ECA Pool meets the balance of its power needs with power purchased from a variety of sources on the open market. Most of this power today is coal-fired steam in origin. The amount historically purchased is also shown in Fig. 7.

Fig. 7. ECA Coal Assets Monthly Power Production



4.1.6. Transmission

Two 115 kV transmission lines presently serve all of LA County, LANL and non-LANL. Each serves as a back-up for the other and must be able to carry the full maximum load for reliability. The import limitation is currently 116 MW on the Norton Line. The current estimated cost to re-conductor Norton Line to increase its capacity is $12 million to $15 million plus land use costs. This improvement would shift the import limitation to the Reeves Line with its limit of 131 MW. Reconductoring the Reeves Line in addition to the Norton Line would increase the import limitation to more than 200 MW. Reduced overall peak use (largely by LANL, as it is the bulk of the load) and/or local power generation or storage could mitigate the need for such an upgrade.

4.1.7. Firming

Today, "spinning reserves" at conventional steam power plants, quick-starting natural gas peaking plants, and the TA-3 generators provide back-up for power fluctuations from plant or transmission interruptions for which replacement power has not been previously scheduled.

4.2. Potential New Carbon-free Resources

4.2.1. Nuclear

Nuclear fission power has the virtue of being both carbon-free and firm, unlike many other carbon-free primary sources. Broad efforts have been underway for several years, including work at LANL, to restart the nuclear power industry by developing both new reactor technologies and plant designs that are safer, less expensive to build, and entail less economic risk for their owners. Many of these efforts are based on Small Modular Reactors (SMR's). Using various technologies, each of these would typically generate 50-300 MW, vs. the 1000 MW of current designs. A single design could be licensed and "mass produced" in factories rather than each plant being unique and subject to the entire very expensive, protracted, and unpredictable licensing process.

Nuclear power offers an attractive source of base power for Los Alamos.

LA County recently became a member of the Utah Associated Municipal Power Systems (UAMPS), which serves municipal utilities in eight western states. Among its numerous other projects, UAMPS is proposing to build a nuclear power plant, possibly at the Idaho National Engineering Laboratory in Idaho Falls, which would be comprised of up to a dozen 50-MW pressurized light water reactor modules. The modules are purported to incorporate a passive safety design which is expected make it physically impossible to "melt down." The project plans to be on-line in 2023, producing wholesale power at a projected cost of $72 / MWh (in 2015 dollars). (Both cost and schedule projections of project advocates should always be considered critically.) If the project goes forward, LAC would have the opportunity to purchase some fractional ownership interest which could entitle it to up to 9-10 MW of firm power, more than the County would need absent some form of extended cooperative agreement with DOE/LANL.

4.2.2. Solar Photovoltaic Generation

Solar photovoltaic (PV) cells produce carbon-free power whenever the sun shines. That is both their virtue and main drawback. PV can be practical at almost any size scale. It is relatively easy to add capacity incrementally. Distributed installations today are typically sized to produce up to 3-10 kilowatts (kW) on residences and up to 200 kW on commercial buildings. Solar PV can be generated locally. If also firmed locally, it could reduce import transmission capacity requirements.

Ideally, PV sources should be geographically distributed to reduce the impact of any localized cloud cover, but that may be difficult with the limited size and PV location options in LA County. There are thousands of residential rooftops in LA, but many of them are not oriented efficiently for PV production or are shaded. It is not known how many have solar PV potential.

Utility-scale solar fields typically require 3-6 acres to produce one megawatt of peak power output. Several potential sites have been identified in the County, most of them on DOE property. Collectively, nine large sites have been identified on DOE property that totals approximately 500 acres, providing space for a peak capacity of more than 80 MW.[5] This includes space for a second 1 MW array on the County landfill cap. It does not include potential sites on County or LA Public Schools (LAPS) property, such as east of the Middle School on North Mesa.

Many residents do not have suitable locations at their homes for PV installations. One or more utility-scale PV fields could be administratively divided into "individual" arrays, output of which is credited to their owners or members just as would be the output of arrays at their property. These "community solar gardens" could be built and operated by DPU or a private entity.

Costs for PV cells have been steadily falling. A current estimate for utility-scale PV installations, without subsidies, is about $80 / MWh for generation only.[6] Firming would be in addition. This is roughly half the unsubsidized unit cost of residential PV power.[b]

4.2.3. Firming (Storage) for PV

Requirements. The current value of PV is largely in "peak-shaving" which works best if the peak load matches PV's maximum output during the day. While this is the case for LANL and hence Pool loads, the County's peak demand occurs in the evening. (See Fig. 3.) Firming is expensive and efforts should be made to minimize the amount of buffering and firming needed for any PV system.

Currently, LA County pumps water to storage tanks overnight to take advantage of lower electric rates. In the future, this load could be shifted to daytime to match PV generation. Flexibility in charging electric vehicles (EV's) could provide significant load shifting in the future assuming they become a significant part of the electric load as anticipated.

Firming requirements for PV are fundamentally different than those for base power (as covered in Sec. 4.1.7) and they span different time scales.

Fast-responding, short-duration storage (< 30 min.) is necessary to buffer unanticipated changes in cloud cover, precipitation, and loads. Conventional static batteries (e.g., lead acid, lithium-ion) are the most obvious current choice. High power density capacitors ("ultracapacitors") might eventually be able to fill this role.

Several approaches have potential for intermediate-duration storage (10 – 120 min.). Static batteries, flow batteries, and pumped hydroelectric storage are all possibilities for the future – several years from now. If enough PV is employed before any of these sources are available, fast-starting fossil-fuel-fired generators could provide firming.

---

[b]Current costs for fully installed residential PV systems total about $0.113 / kWh or $113 / MWh. (based on $6.60 / Watt installed system cost, 8 hours / day generation at peak capacity and 20 year lifetime. Including financing, total system costs are closer to $175 / MWh. These estimates do not include any inverter replacements or other maintenance.

Longer duration storage requirements (2 – 16 hours) could also potentially be met by static batteries although flow batteries and pumped hydro may be more economical for utility-scale storage. In the near term, purchased power is the most practical choice for the predictable evening, and overnight firming of PV and certainly for any multiday duration.

Static Batteries. Static batteries contain individual cells, each including both the oxidation-reduction (redox) system that controls the charge and discharge rates and the capacity system that determines how long the cells will be able to produce power. These cells are stacked to make a battery of the needed size. The lithium-ion (Li-ion) battery, familiar in portable applications from cameras to laptops to EV's, is most often put forward as the battery of choice for PV storage purposes. It features a high discharge rate, but it takes a fairly long time to recharge, doesn't respond well to deep discharges, and has a limited number of charge/recharge cycles. Internal short circuits render a cell or perhaps the entire battery inoperative.

The Li-ion batteries currently used in EV's, which each store 20-80 kWh today and likely several times that in future vehicles, can now be used to store power for an individual distributed PV installation, and they have the potential to be "smartly" integrated into the distribution system as a whole.

Flow Batteries. Flow batteries have flexible energy capacities that depend on the size of the electrolyte storage tanks, and a separate electron transfer (redox) unit that determines the charge and discharge rates. Flow battery redox units can have similar problems to static batteries, but if this unit fails, the tanks of electrolyte remain to be used with a new redox unit. A variety of flow batteries are still in development based on different chemistries, but the vanadium (Vd) flow battery has been used fairly widely around the world in the 10-50 kW size, and larger utility-sized units, up to 4 MW, have been installed in Japan. The Vd-flow battery seems to be the simplest design, is expected to be unaffected by deep discharge, and appears to be able to accommodate an unlimited number of cycles without falloff in power output. One unit has been reported to have been cycled over 270,000 times in a 3-year period.[7]

One major advantage of the Vd-flow battery is the fact that the same chemical, albeit in different oxidation states, is used for both oxidation and reduction, and at the end of the battery's useful life, the Vd can be recovered and recycled. Barring unforeseen issues, such as a rapid rise in the cost of vanadium, it is likely to be the flow battery of choice for utility storage applications.

Batteries are currently very expensive for significant storage. Numerous forecasts suggest the initial price of Li-ion batteries may drop to a few hundred dollars per kWh soon although their lifetime is still uncertain. Vd-flow batteries may also decrease in price similarly as the number of units produced ramp up. If those price drops materialize and lifetimes are proven adequate, batteries would become more practical.

Pumped Hydroelectric Storage. Pumped hydro storage has been in widespread use for more than a century. It utilizes the gravitational potential energy stored in water pumped to an upper reservoir during periods of low demand and released (through the same motor-generator turbine(s)) when additional power needs to be generated. LA County does not have large areas available for storage reservoirs, but does have large elevation differences. At least three areas have potential.

Pajarito Mountain could support an upper reservoir, possibly in the form of enclosed water tanks similar to those used for water storage on the west side of the townsite, up to 3000 ft. above a potential lower reservoir of or around the Los Alamos Reservoir at 7300 ft.

A second option would place the upper reservoir in similar large tanks on a mesa of TA-70 or TA-71, south of Pajarito Acres. The Rio Grande, nearly 1000 ft. below, would be the lower reservoir. A variation on that approach would involve an upper reservoir behind a dam in Potrillo, Water, or Ancho Canyons. The volume of the reservoir could be much larger although the head would be lower. Getting dam construction materials in placeFill material would be a challenge as would access to the river in that area for both construction and maintenance. Parts of the study that has gone into accessing San Juan Diversion Project water should be applicable.

A third option would utilize as the upper reservoir the Pajarito Canyon dam built for emergency flood control by DOE/LANL after the 2000 Cerro Grande fire to protect (the now-abandoned) TA-18. The lower reservoir would again be the Rio Grande. That dam was never intended to be permanent or regularly used; LANL may "remove" it in the near future. The dam could be evaluated to determine if it could be upgraded to a permanent dam or if the dam material could be reused for a permanent dam there or in one of the TA-70/71 canyons.

<u>Other.</u> Many other storage technologies have been proposed or developed to various stages. These include hydrogen fuel cells, flywheels, compressed gas, regenerative braking, and cryogenic systems. Only the first of these may be mature enough for consideration for an operating utility, but all should be watched.

4.2.4. "Long Shots"

<u>Wind.</u> As a generating technology, wind energy is fairly mature and economically attractive. LA County does not experience enough wind locally for practical generation. But wind farms are spread across the Great Plains that start in eastern NM. The major challenge with wind is firming. Variation time scales are longer than those of PV (hours, days, or even longer). Physical back-up with batteries, etc. is not practical. Wind is typically firmed today with fossil-fueled sources. It is not clear how it could be practically firmed from carbon-free sources to meet BPU's eventual goal.

<u>Local SMR.</u> Los Alamos would be an ideal location for an SMR demonstration project that could produce a large fraction of the combined power required by DOE/LANL and LAC. Such a project would be far too large and risky for LAC DPU to even consider by itself. DOE/LANL would have to take the lead, but has so far evidenced no interest.

<u>Cochiti Dam Hydroelectric Plant.</u> A hydroelectric power feasibility study of Cochiti dam was conducted by the Corps of Engineers in 1984 under Congressional mandate. Cochiti dam is a flood and sediment control dam which normally experiences peak flows during the winter, providing some seasonal complement to LAC's existing dams at Abiquiu and El Vado. Several

technically and economically viable alternatives for producing hydropower at Cochiti dam were identified. The most conservative of those would utilize a 5 MW generator to produce an annual average of 35,000 MWh of electricity. Cost in 1984 was about $12M. Depending on how the dam is operated, it might be possible to increase that annual electricity production substantially, to as much as 88,000 MWh.

Addition of a power plant to Cochiti dam would have negligible impact on archeological resources in the area. However, in the early 1980's, Cochiti Pueblo vigorously objected to even further study of the hydroelectric potential of the dam. Their objections appear to be founded in a poor relationship with the Corps of Engineers growing out of the original construction of the dam around 1970. Any consideration by LA County of adding hydroelectric power to Cochiti dam would need to start with and be sensitive to the interests of the Pueblo. Several overtures to the Pueblo over the years seeking to explore the hydroelectric potential of Cochiti Dam have been unproductive.

Geothermal. There are no known geothermal resources underlying the County or immediate vicinity. The western Jemez Mountains have geothermal sources which have been explored extensively. Exploration in the western Valles Caldera in the early 1980's was motivated by the dream of producing 100-1000 MW of electric power. The resources were disappointing in this respect and eventually abandoned. However, there were indications they could produce at least 20MW of electric power continuously. Unknown are the depletion rates and potential effect on surface geothermal features in the Jemez Valley. Underground resource rights in this area are now owned by the Valles Caldera National Preserve and no longer accessible. The feasibility of the hot dry rock technique for extracting heat energy from the earth was explored at Fenton Hill. That site might produce up to 6 MW of electric power.

The U.S. Forest Service has currently opened other areas of the Santa Fe National Forest on the western side of the Jemez Mountains to geothermal exploration. This initiative is too preliminary to consider for supplying power to LA, but bears monitoring.

Solar Thermal. Solar thermal systems heat a working fluid, usually a molten salt, with concentrated (focused) solar energy. The hot salt then heats water to make steam for a conventional turbine generator or can be stored and utilized for later generation. The inherent storage makes this an interesting option. But it is complicated and typically requires large areas of quite flat land, which is lacking in LA County. It is a technology that also bears monitoring.

Biomass. The forests of northern NM have seemingly large amounts of excess wood. While wood is a hydrocarbon that produces CO_2 when it burns, it absorbs CO_2 from the atmosphere while it is growing. The 2008 LANL/DPU Study concluded there was not enough wood within a 100-mi. radius of Los Alamos to sustain a 5 MW generator and prohibitively expensive.[8]

The possibility may exist to buy shares in the Chama Peak Land Alliance which is currently investigating the feasibility of a biomass-burning electricity generation project in the far northern part of the state.[9]

4.3. Future Resources: present – mid-2020's

LAC's transition to carbon-free power is constrained over the next decade by three contracts. Actions during this period should focus on positioning the County to wean itself from carbon-based power after that.

4.3.1. Energy Coordination Agreement

The Federal government is also moving towards more carbon-free power. DOE/LANL power supply requirements are dictated by considerations entirely separate from LAC's and not under the County's control. Present guidance extends only to 2025. To what extent DOE/LANL will pursue carbon-free power after that date is unknowable, given the normal political uncertainties over such a period.

The present ECA expires in 2025. The power scheduling function LAC has provided to DOE/LANL (and Sandia National Labs / Kirtland AFB) may continue to be mutually beneficial after that. Any continuation of the power pooling function of the ECA should not dilute LAC's carbon-free resources. It could pool only carbon-free resources or have separate pools for carbon-free and carbon-based power.

In the interim, LAC cannot act unilaterally with respect to its resources, but must coordinate any actions with DOE/LANL.

4.3.2. San Juan Generating Station

Two of SJGS's four units (Unit 2 and Unit 3) are scheduled to shut down in 2017. Additional equipment reinvestment will be required in its supporting coal mine by about 2025. Additional environmental constraints or upgrade requirements might well be expected later in that decade.

LAC's present Plant Participation Agreement with the other co-owners of SJGS expires in 2022. The increasing costs of environmental compliance, uncertain regulatory future, and additional capital investments required in the associated coal mine after the current "long-wall" mining equipment wears out in about 2025 suggest the plant is likely to be retired some time in the mid-2020's. Even if it continues to operate, costs are likely to keep rising above the presently projected $55 / MWh rate.

While reserves for presently anticipated closure costs are included in current power costs, the County retains uncertain long-term post-closure liabilities that may not be shared with DOE/LANL after the ECA expires.

The County will need to decide by 2018 whether to allow its interest in SJGS to expire in 2022 or negotiate an extension. Power from the coal-fired SGJS is carbon-based and moderately expensive. FER recommends LAC divest itself of SGJS ownership in 2022 or when most opportune thereafter.

4.3.3. Laramie River Station

DPU believes its contract for LRS power could be sold today since it is for comparatively inexpensive power at present. Sale value is unknown. Sale of the contract would have two benefits. It would relieve LAC of that long-term obligation to carbon-based power and it would eliminate the inevitable rise in rates for power from that plant. Replacement power would have to be purchased for the ECA Pool. Such replacement power could come from firm wind, gas turbine, or (temporarily) coal sources. Near-term costs would likely be higher although partially offset by proceeds from sale of the contract.

If the County has no choice but to "take-or-pay" for LRS power for the life of the plant, it will be impossible to reach BPU's carbon neutrality goal until the plant is retired, likely around 2040.

Because the present price for LRS power is so low, DPU believes there could be a market for LAC's contract. Sale is likely to become increasingly less beneficial, if not impossible, as time goes on. The market for divestment should be investigated soon.

While DPU forecasts LRS power costs to remain around $27 / MWh for the balance of the period, this cost is likely to rise significantly as environmental upgrades are required. Downtime can also be expected to increase to install the upgrades.

4.3.4. Purchased Replacement Power

If SJGS and/or LRS power contracts are terminated before replacement resources are in place, substitute power will need to be purchased (for the entire pool, if before the ECA expires, for LAC alone after that). Replacement power could be derived from gas or wind although the latter would have to be firmed with gas-derived power. Temporarily, coal could be used as a last resort. The long-term environmental and economic benefit would have to be considered against short-term cost increases, if any. Overall, purchased power costs are expected to rise from around $40 / MWh currently to around $60 / MWh by 2025 as more expensive resources are used to supply the grid.

4.3.5. Utility-Scale Photovoltaic

The amount of solar PV that can be beneficially used even for peak-shaving is limited by the storage available to buffer short-term fluctuations in PV power output.

Present agreements with LAC's balancing authority (PNM) subject the Pool to penalties any time the power it consumes is more than ±2 MW (the "bandwidth") from the amount scheduled. Most scheduling (purchasing or sale) of power is done a day in advance. Spot market (usually more expensive) power can be scheduled up to two hours in advance. Cloud cover variations can change the output of an individual PV installation sharply in seconds and even that of distributed solar fields (e.g., spread across the townsite or White Rock) in a few minutes. In the absence of instantaneous buffering, the allowed bandwidth could often be exceeded.

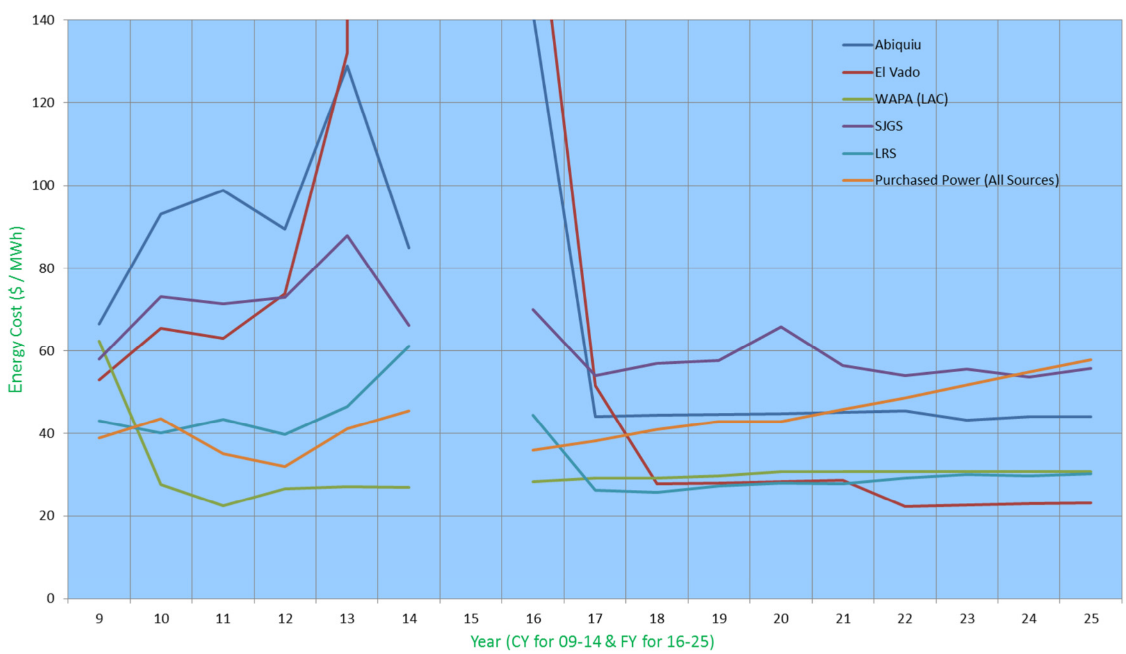
Preliminary results from a concurrent LANL study of the effects of distributed PV on Pool bandwidth[10] suggest a practical limit on total PV even with significant storage on the order of a few megawatts. The full results of that study may be sufficient to establish more specific limits. If not, a follow-on study should do so. A proposed 2nd megawatt of PV power at the landfill would probably not result in frequent bandwidth exceedances given the existing battery storage. It may also be possible to "buy" additional bandwidth. A cost-benefit analysis of such a purchase would be needed.

4.3.6. Costs

Historical and projected energy costs for existing resources are shown in Fig. 8. The generally lower costs in the future are based largely on retirement of acquisition debt for the plants. For a fair comparison, costs projected by DPU for the Abiquiu and El Vado hydroelectric plants have been increased by 3% / yr. of their estimated current capital value to account for major maintenance and capital replacement. That amounts to $500K / yr. for Abiquiu and $120K / yr. for El Vado. The huge current apparent spike in El Vado costs arises from the generator rewind – both the costs for the work and the reduced (or zero) output over which plant expenses are spread.

Transmission losses and wheeling costs are typically less than ten percent of energy costs. That is small enough compared to generating uncertainties that they are ignored in this study.

Fig. 8. Energy Cost for LAC Resources



4.4. Future Resources: mid-2020's through 2040

4.4.1. Hydroelectric

LAC's three hydroelectric resources (Abiquiu, El Vado, and WAPA) will provide very roughly half of LAC's power post-ECA. Well-maintained, they should provide carbon-free, inexpensive (~$40 / MWh in current dollars) power to LA consumers for several more decades.

Power available from LAC's two hydroelectric dams is subject to considerable variation, some predictable, some not. There is no obvious firm physical source that provides power on a seasonally complementary basis to the hydroelectric plants. As history shows (Fig. 6) year-to-year variations can be considerable, too. Effects of the long-term drought in the southwest are only beginning to be seen, but could become more severe.

LAC's remaining power needs after the mid-2020's can be met by one or a combination of the following sources.

4.4.2. Laramie River Station

If LAC is not able to beneficially dispose of at least some of the LRS contract, the County may have little choice but to "take-or-pay" an amount which has historically averaged more than 8 MW, slightly more than the County's average historical need. All other major options would be effectively precluded for the life of that plant.

4.4.3. Nuclear

If UAMPS or a similar nuclear source comes to fruition in the mid-2020's, it could provide reliable base power to LA County consumers. With historical hydro output and County loads, 6 MW would provide the average amount of energy needed per year. Surpluses when the hydros are producing would need to be sold. More base power would be needed in the fall and winter when the hydros produce little.

4.4.4. Local Utility-Scale PV with Storage

Any significant use of PV after 2025 requires either a power-swapping arrangement with LANL, load-shifting to match PV's daylight production, or storage sufficient to match the load profile. Costs for PV generation and ancillary equipment will be lower than today's. How much lower is difficult to predict. Costs for storage are also a major driver. Battery costs are high but declining. Feasibility and cost for pumped hydro storage should be determined. Development of other storage technologies should be monitored.

4.4.5. Purchased Power

LAC could simply purchase the power not supplied by its hydros or other sources. This is the most flexible solution. It minimizes risk inherent in asset ownership but subjects DPU's consumers to market price risks. The seasonal cycle in hydroelectric generation can be complemented with seasonal power purchase contracts.

Power purchased should be derived from carbon-free sources, if the cost is not excessive compared to carbon-based sources. This would allow, if economically necessary, a flexible transition to carbon neutrality by 2040.

4.5. Summary of Future Resource Options and Strategies

Table A summarizes LAC's resources and costs for the past six years, next decade and post-ECA eras. Cost estimates past about ten years are speculative for PV, battery storage, and any other new technology.

Table A. Summary of LAC Electric Power Resources and Cost

			Annual Energy Cost ($/MWh in 2015$)		
Resource	**Capacity**	**Energy***	**Recent**	**Near-term**	**Post-ECA**
	(MW)	**(MWh/yr)**	**(2009-15)**	**(2016-25)**	**(2025-40)**
----------------	--------------	--------------	-----------------	-----------------	-----------------
Combined Hydro	1-26, by season	40 - 100K	$90	$50	$50
SGJS	36	200-250K	$72	$58	Retired
LRS	10	55-85K	$45	≥$26**	>$26**, if still contracted
Nuclear (e.g., UAMPS)	6-10	45-75K	N/A	N/A	≥$80
DPU PV (non-firm)			N/A	~$80	<$80
Purchased (all sources)	As needed	As needed	$40	$46	??

*Energy is for the entire ECA Pool

**Full impact of environmental upgrades on costs may be higher

Hydroelectric power will anchor LA energy resources after the mid-2020's, if LAC is separate from any ECA-like pooling arrangement with DOE/LANL. LRS is the key to providing the balance. If the "take-or-pay" power purchase contract there cannot be practically sold, LAC may have little choice until the plant is retired. Power from LRS would be base power. More power will have to be acquired in winter months when the hydros are not producing and surplus power sold during the summer months when it is.

If the LRS power purchase contract can be sold, there are three basic options after the mid-2020's." (1) Secure base load power from a nuclear or other base power plant, again buying or selling the complement of the hydro power. (2) Build utility-scale PV and storage, almost certainly combined with some purchases or sales and augmented by distributed PV and storage. (3) Purchase all other power needed.

Choosing between these options will depend on (1) whether the LRS contract can be sold and at what price, (2) the viability (in all respects) of the UAMPS nuclear plant project, and (3) availability of land and practicality of storage for large-scale PV. As these questions are answered, more detailed analysis on remaining options will be needed to narrow them down. While LAC's power resources will not dramatically change for another decade, contract and construction lead times will require major decisions early in that period.

Meanwhile, DER's will become more important to BPU's customers and in BPU's relationship with them. The distribution system will have to get smarter to take advantage of cheaper PVpanels, smart meters, smart inverters, etc. The big unknowns largely revolve around storage.

4.6. Summary of Resource Recommendations

1. A definition, such as the one suggested in this report, should accompany or be included in BPU's "carbon neutrality" goal. (Sec. 2.1)

2. Incorporate "environmental impact, specifically greenhouse gas production," as a factor to be considered in all resource decisions. (Sec 2.2)

3. Encourage more efficient use (conservation) of electrical energy by LA consumers. (Sec. 3.2)

4. Support replacement of petroleum-fueled motor vehicles with all-electric vehicles. (Sec. 3.2) Consider locating more EV charging stations around the County or at LANL.

5. Maintain and operate the Abiquiu and El Vado hydroelectric plants as the backbone of LAC's long-term future electrical supply. (Sec. 4.4.1)

6. Adopt policy regarding extension of ECA such that any continuation of its power pooling function will not dilute LAC's carbon-free resources. (Sec. 4.3.1)

7. Plan to exit SJGS share ownership in the mid-2020's, under the most opportune circumstances. (Sec. 4.3.2)

8. Explore sale of the LRS purchased power agreement. Sell LRS if and when economically feasible and consistent with the needs of the ECA Pool, considering the continued carbon production and increasing regulatory risks associated with that plant. (Sec. 4.3.3)

9. Continue to explore participation in the UAMPS nuclear power project as a replacement source of base power, carefully considering plant safety, realistic life-cycle costs, and potential for a cooperative power-sharing arrangement with DOE/LANL after 2025. (Secs. 4.2.1 and 4.4.3)

10. Pursue access (transfer or long-term lease) to suitable utility-scale PV sites presently owned by DOE/LANL. (Sec. 4.2.2)

11. Monitor feasibility and costs for utility-scale battery storage, including at least Li-ion and Vd-flow batteries. (Sec. 4.2.3)

12. Explore feasibility (including access to present DOE/LANL lands) and estimate costs of pumped hydro storage somewhere within LA County. (Sec. 4.2.3)

13. Evaluate feasibility, including market interest, for a community solar garden if bandwidth or other limits are not being approached by individual installations. (Sec. 4.2.2)

14. Explore current interest in a hydroelectric project at Cochiti Dam with the Pueblo. (Sec. 4.2.4)

5. Distributed Energy Resource Policy

5.1. History of DER in LA

The first solar PV system was installed in LA County in 2006. The number of installations have increased over the ensuing years along a generally exponential curve. There were eleven installations in 2011 and 30 in 2013. Today, 59 installations have been approved. Most of these have been residential rooftop or ground-mounted installations. LAPS installed 50 kW of PV (using fixed-mount, single-axis, and two-axis mounts) at the LA Middle School in 2011. Smith's new Marketplace has 100 kW of PV capacity on its roof. Total installed capacity in LA County today is about 380 kW.

So far, DPU permitting requirements have been based on safety of the distribution grid. Inverters that convert the DC power from the solar PV panels to AC power to match the line must be designed to prevent "backflow" from partially energizing a failed or deliberately deenergized line, creating a hazardous situation for utility line crews.

DPU bills PV customers today on a modified net metering basis. Two meters separately record integrated consumption and production by the customer. If the former exceeds the later, the customer pays the normal retail energy rate, currently $0.1152 / kWh. If the customer supplies more power to DPU than is consumed (over a year), the customer is reimbursed for that net production at the average wholesale rate the ECA pool has paid for power over that year. Most other utilities that bill by net metering reimburse at the same retail rate as they charge.

5.2. Objectives of DER Policy

5.2.1. Distribution System Stability and Load Fluctuation Tolerance

Of concern to all is the physical effect on the local electric distribution system of large numbers or amounts of distributed sources feeding into it.

Phase Stability. Currently available inverters (either while gaining phase synchronism with the local grid or during an internal phase-lock failure) may supply or absorb reactive power if the connection to the local grid has already been established. Depending upon the phase separation between the inverter output and the local grid voltage, transient voltage fluctuations can occur that exceed an allowable magnitude and can propagate outwards on the local grid for some (presently unknown) distance.

Amplitude (Voltage) Stability. Fluctuating amounts of power coming onto the distribution system, if large enough, can cause voltage fluctuations, just as fluctuating loads do.

Harmonic-induced Instability. The conversion process from DC to AC in the inverter does not produce a pure 60 Hz sine wave. The output waveform contains small amounts of energy at harmonics (multiples) of that fundamental frequency which can excite potentially harmful resonances in the distribution system.

Improvements in inverters, driven by utility mandates in California and Hawaii, are expected to mitigate these effects. Utility mandates in California and Hawaii are driving inverter development in the U.S. Improved ("Phase 1") autonomous inverters can be expected in another year or two with inverters designed to allow dispatching of power by utilities (Phase 2 and 3 inverters) in years after that. These "smart" inverters should permit "tuning" to actually help stabilize the distribution system. Until they become available and a local standard, the amount of PV power that the distribution system can safely absorb will remain limited by these concerns.

Knowledge of these engineering limits and effects of potential changes to the system will be essential to intelligently managing growing distributed resources.

One example of system modeling that may be useful for guidance is from London, Ontario.[11] A similar model for LA County should be developed. "IEEE Standards for PV interconnection to power utilities"[12] as well as inverter manufacturers specifications provides an approach.

Load Fluctuation Tolerance. Another type of limitation on the amount of PV the system can absorb is the contractual bandwidth limit discussed in Sec. 4.3.5. How the available supply bandwidth is apportioned between utility-scale and distributed PV will have to be determined on an on-going basis as the two approaches (and their associated economics) evolve.

As noted previously, solar output varies. It has predictable seasonal and diurnal cycles and less predictable shorter term variations from cloud cover. To be most valuable to a utility and all its customers, PV must be firm and dispatchable, which requires storage to match generation and loads temporally. There are two types of storage needs. Short-term storage would buffer the variations in sunshine (and modest unanticipated load changes) for durations up to two hours. Overnight storage would "bank" solar energy produced during the day to meet the County's peak loads in the evening and carry on overnight. Ideally, that stored power should be available to the utility when needed, i.e., be dispatchable.

Utility engineering would favor all electrical sources be dispatchable. There is a similar engineering advantage to having such centralized control of loads, also. Of course, customers, especially individual retail customers, prefer personal control over their electricity utilization. Customers like to use electricity at their own discretion and supply any surpluses to the utility on a secondary basis.

5.2.2. Rate-making Principles

Traditional public utility rate-setting policy is generally based on the principles[13] which require public utility rates to:

- Be stable, predictable, and easy to understand
- Reflect fair cost allocation to rate classes
- Reflect present and future private and social costs
- Not subsidize one class of customers at the expense of others
- Promote efficiency and innovation; discourage wasteful consumption
- Provide adequate and stable revenues to the utility

None of these principles is absolute; balancing has been and will continue to be required. Interpretation of principles and their relationships will change as the utility industry evolves. But basic principles do not change.

All rates, for consumption, supply (distributed generation), and management of both should be established recognizing principles like these.

5.2.3. Charges Relative to Service Costs

The total cost to DPU to provide electricity to any customer has four components:

- Energy charges for the electrical energy itself (roughly half the total cost)
- Demand charges for the capacity to meet peak power demand at any given time
- Capital investment and Operating and Maintenance (O&M) costs to build, maintain, and operate the distribution systems to meet any demand – within their class of service – at any time by individual customers and all of them collectively
- Administrative costs, including billing to customers.

Until recently, DPU (like many utilities both public and private) lumped all costs together and charged customers, particularly residential customers, proportionally to their energy use. There was no service or demand charge. Demand costs are a separate charge for larger commercial customers (≥ 50 kWh / month), the County government itself, and LAPS. DPU now includes a small service charge (a meter charge) for every meter, i.e., customer. It covers meter reading and billing costs.

With most of the costs lumped into the energy charge, effectively large users are subsidizing smaller users. Whether this is good policy or not is beyond the purview of the FER Committee. But it does complicate establishing a fair rate structure for customers who are also producers, i.e., DER customers.

5.3. Rate Structure Options

5.3.1. Align Charges with Service Costs

Fairly aligning customer charges with energy and service costs would be facilitated by a rate structure that identifies each cost separately. For that reason if no other, utility charges are likely to become more granular across the industry as time goes on. Rate structures in the near term could start moving DPU and its customers in that direction without being unduly complex.

5.3.2. Net Metering

Net metering is simple to understand and implement. It does not require smart meters. It bases charges on the difference between the amounts consumed and generated instead of recognizing that they are quite different. Most notably, a customer who produces as much or more power than he consumes pays nothing beyond the small base meter charge towards the fixed costs of providing seNrvice.

Net metering also obscures what is actually being paid to DER energy producers by the utility for the power they provide to it. It is virtually impossible to determine whether producers are being paid too much or too little as neither economic nor non-economic factors in the value of that distributed generation are identified. The current reimbursement to DER producers is implicit and arbitrary. This is not a good approach to public policy.

There are more transparent ways to compensate DER owners for the energy they provide to the system. Different rate structures can encourage “smarter” use of the utility system by all who are connected to it.

5.3.3. Separating Consumption Charges and Generation Payments

Service to DER customers requires the same distribution system with the same capacity as for non-DER customers. Billing and other administrative costs are also essentially the same for all customers. Charges for these services should not distinguish between DER and non-DER customers. The most straightforward approach would charge separately for services provided and energy consumed with the same rates for every customer (DER and non-DER). How service costs should be divided between a fixed service charges and energy charges is outside the scope of FER’s charge. By assuring that DER customers pay for fixed costs and energy consumption at the same rate as non-DER customers, the focus can shift towards fair payment for the energy DER customers supply to DPU.

5.3.4. Rate Structure Options for Distributed Generation

Deployment of smart meters is expected to be completed in LA County in about two years. This opens up opportunities for more sophisticated rate structures than have previously been possible, both on the consumption and generation sides. FER focused on the generation side.

Various approaches have been considered or implemented by other utilities to try to be fairer to all consumers while encouraging DER growth. These include various forms or even combinations of a few basic approaches. All assume that all customers, those with and without generation capability, pay the same rates for all power they consume from the distribution system. The differences are in how the power provided to the distribution system by distributed energy producers is valued and paid for by the utility. All three basic pricing approaches have analogs on the consumption side. These approaches include:

1. Feed-in-Tariff (FIT). This is a fixed, long-term price the utility pays for distributed power supplied to it.

2. Real-time pricing (RTP). This reimburses the DER generator based on the instantaneous avoided cost of power that does not have to be acquired from other sources. This is more commonly used for larger institutional customers than for residential.

3. Time-of-Use Pricing (TOU). (This might be better called "Time of Supply" but TOU is commonly used in the industry for both consumption and generation.) This sets different reimbursement rates for different times of the day, depending on how valuable the power may be considering loads and wholesale prices.

5.3.5. Value of Solar

PV is a carbon-free resource. It has a non-economic value beyond just the avoided cost of the carbon-based power it replaces. That value will decline as other carbon-free resources also continue to displace carbon-based sources.

PV's non-economic value is the basis for the tax credit subsidies it has enjoyed. The 30% Federal and 10% NM state credits are both due to expire at the end of 2016. Some extension or gradual phase-out of either or both of these is possible, but not likely. The rapid pace of PV deployment is likely to be dampened at least temporarily as these subsidies disappear.

Eventually, PV must stand on its own in competition with other carbon-free sources. Electricity from distributed PV has historically cost about twice that of utility-scale PV, with its economies of scale.

A significant benefit to PV is that it is local, i.e., within LA County. If it can be managed to reduce peak loads, import transmission capacity requirements can be reduced.

One approach to recognizing solar's value is the explicit "Value-of-Solar Tariff (VOST). This establishes some rational basis for the value of PV-generated power relative to other power imported into the distribution system. It can include both economic and non-economic considerations and makes the value of solar PV explicit and visible. VOST can be added to or explicitly incorporated within any of the three basic rate structure options outlined in the previous section.

A major challenge with VOST is establishing a dollar value. Various entities trying to do so have come up with wildly different values, ranging from \$0.037[14] to \$0.33[15] / kWh (\$37-\$330 / MWh). A Federal standard for the non-economic "Social Cost of Carbon" (SCC) puts it in the range of \$0.011 - \$0.054 / kWh in current dollars for coal-generated electricity in NM.[16] Minnesota is the only state so far to codify a methodology for establishing VOST's. Their approach includes seven avoided cost factors plus the SCC. It values solar at about \$0.125 / kWh (2014 dollars) for their specific circumstances.[17] Roughly 80% of that value is economic and 20% SCC. This methodology may be a useful example, but LAC's value would certainly be different.

5.3.6. Enhancing Solar's Value with Firming and Dispatchability

All VOST's so far implemented consider only non-firm PV. The value of solar is very different if it is firmed (by storage or other means) and dispatchable, i.e., so that the utility can effectively manage the energy generated.

The biggest challenge with PV is the obvious fact that it produces power only during daylight hours. Today, the maximum load on the Pool also typically peaks during the day. However, LAC's peak load is typically in the evening. For PV to be a major source of electric power for LAC in the post-ECA era, there are two options: (1) swap power with DOE/LANL or other entity that peaks during the day, supplying it during the day and getting reimbursed in evenings, or (2) store energy during the day for evening and overnight consumption. The latter gives LAC more control over its own destiny, but is more expensive.

Centralized utility-scale storage offers more options and economies of scale not available to the individual consumer, just as utility-scale PV fields are more economical than distributed PV.

Reimbursement for distributed electricity producers should encourage storage. FiT does not do that. (Neither does net metering.) RTP may encourage storage at the price of considerable complexity. TOU could be easily tailored to encourage PV storage from daytime to evening.

PV has even greater value if energy stored is dispatchable by the utility (once the inverter technology is available). Mandatory utility control of residential systems could be viewed as "big brother" interference with personal property and the freedom to use it, although it may be acceptable if limited to short durations. Rate incentives for making stored power dispatchable are likely to be a far more acceptable approach; it gives individual customers a choice.

A different approach to encouraging firming and dispatchability would be for DPU to directly supply (by sale or lease) or subsidize distributed storage hardware, requiring that energy stored within it be dispatchable. FER did not explore this alternative.

5.4. Summary of Near-term Action, Policy, and Rate Structure Recommendations

Distributed energy policy and rate structures in the next few years should:

A. Promote increased distribution system stability.

B. Base payments for DER production on a transparent rate structure considering avoided costs and non-economic value of solar energy.

C. Encourage or require storage and, ideally, dispatchability, of distributed energy resources as technology permits.

To accomplish these objectives, the following steps are recommended.

1. Complete smart meter implementation for all customers. This will enable more flexibility in billing and help customers understand and manage their use or production. (Sec. 5.3.3)

2. Develop an engineering model of the distribution system that will indicate how much distributed generation can safely be absorbed. (Sec. 5.2.1)

3. Complete studies to determine how much distributed generation can be tolerated before causing an unacceptable number of bandwidth exceedances. (Sec. 5.2.1)

4. Establish limits, based on the above two considerations, on how much distributed generation can be tolerated in the system. Update these limits as necessary. Make it clear that permit issuance will be suspended once those limits have been reached pending expansion of system tolerance of increased DER's. (Sec. 5.2.1)

5. Require smart inverters (at least "Phase 1") on new systems as they become available. After smart inverters are available, all replacements should be of the smart type. (Sec. 5.2.1)

6. Make it clear in PV installation permits that rates and rate structures are not guaranteed to any point in the future.

7. Determine whether utility-scale, circuit, or neighborhood scale distributed storage, or combination(s) of these approaches make the most sense technically and economically for firming distributed generation. Take that determination into account in any rate structure. (Sec. 5.2.1)

8. For large customers, require or encourage (via rates) that at least large loads be dispatchable. County government can and should lead by example.

9. For large distributed energy producers, require or encourage (via rates) dispatchable storage via Phase 2 or 3 inverters as they become available. Again, the County government can and should lead by example.

10. All DPU customers (DER and non-DER) should be charged the same appropriate rate(s) for all services and energy (not just net energy) supplied by the utility. (Sec. 5.3.3)

11. Implement Time-of-Use pricing for both consumption and generation once smart meters are available to do so. Initial implementation could be based on two rate tiers, peak and off-peak. For residential customers, peak is likely evenings with off-peak all other times. (Sec. 5.3.4)

12. Distributed energy producers should be paid for the power they supply to the utility based on at least the average estimated avoided cost for the time period in which it is supplied. The rate(s) should reflect whether the power is firm and whether it is dispatchable. (Sec. 5.3.6)

13. Consider whether or not a non-economic Value-of-Solar Tariff should be a part of the reimbursement rate structure for PV generation and how it should be phased out as solar's benefits relative to other non-carbon sources decline. (Sec. 5.3.5)

5.5. Summary of Long-term Action, Policy, and Rate Structure Recommendations

Distributed PV will continue to grow and could become a major source of electric power for LA by 2040. To be truly useful at large penetrations, however, firming will need to be developed along with it as costs become reasonable. Dispatchability will further increase its value. Storage, at least for overnight, will be necessary after the ECA pool arrangement expires and daylight peak-shaving value disappears. Overnight storage may be less essential if some temporal power swap arrangement can be made with DOE/LANL.

All policy and rate structures should eventually encourage or require at least short-term storage. Overnight distributed storage should also be at least encouraged unless a power-swap arrangement can be made or it is determined that service can be supplied more practically or economically by DPU utility-scale systems.

All major institutional power loads and probably some large residential loads, specifically EV charging, should be dispatchable.

Energy use costs and supply payments should be based on at least TOU pricing if not RTP pricing. The latter may be more practical for institutional customers and the former for residential and small commercial customers.

6. Acknowledgements

The FER Committee would like to acknowledge the extensive support provided by DPU staff, including Utility Manager Tim Glasco, Deputy Utility Managers Steve Cummins, Rafael De La Torre, James Alarid, and Bob Westervelt, and Power Scheduler/Energy Analyst Jordan Garcia. The Committee especially appreciates the excellent administrative support provided by Jaime Kephart and Julie Williams-Hill. The Committee also appreciates the members of the general public who have taken time to share their thoughts.

References

[1] "Advancing the Science of Climate Change," National Research Council, National Academies Press, (2010), p. 1.
[2] One FER Committee member serves as LANL's Deputy Division Leader for Utilities and Institutional Facility Operations. As such, he abstains from discussion involving the post-2025 future of ECA or potential DOE/LANL intentions.
[3] LAC DPU Customer Surveys for 2005, 2007, 2009, 2011, and 2013.
[4] "Energy Use and Carbon Dioxide Emissions in Los Alamos County: 2000 – 2014," R. B. Gibson, May, 2015.
[5] "Renewable Energy Feasibility Study," App. B., pp. 66-77, LANL and LAC DPU, Nov., 2008.
[6] Lazard's Levelized Cost of Energy Analysis-Version 8.0.
[7] http://www.americanvanadium.com/vanadium-flow-batteries.php
[8] "Renewable Energy Feasibility Study," p. 41 and p. 44, LANL and LAC DPU, Nov., 2008.
[9] "Chama Healthy Forest and Wood Utilization Study," Chama Peak Land Alliance, pp. 31-33, June, 2013.
[10] "SelectSolar/LAC SPV Impact Study, Preliminary Findings," G. L. Toole, LANL Report LA-UR-15-24695, June, 2015.
[11] Varma, R. K., et al, "Determination of Maximum PV Solar System Connectivity in a Utility Distribution Feeder," Proc. IEEE Transmission and Distribution Conference, Orlando, FL, 2012.
[12] "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," IEEE Standard 1547-2003, as amended in 1547a-2014 and 1547-1a-2015. Also, "IEEE Application Guide for IEEE Std 1547," IEEE Standard 1547-2-2008. The original specifications were in "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems," IEEE Standard 929 -2000.
[13] J. C. Bonbright, Principles of Public Utility Rates, Columbia Univ. Press, 1961.
14 "Rate Design for Distributed Generation," American Public Power Association, 2015. Lincoln (NE) Electric example.
15 "Maine Distributed Solar Valuation Study," Maine Public Utilities Commission, March, 2015.
16 "Technical Support Document: -Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866," Interagency Working Group on Social Cost of Carbon, United States Government, May, 2013.
17 "Minnesota Value of Solar – Sample Calculation," MN Department of Commerce, VOS Methodology, April, 2014.