The Impact of Wide-Scale Implementation of Net Zero-Energy Homes on the Western Grid

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ABSTRACT

Pacific Northwest National Laboratory conducted a study on the impact of wide-scale implementation of net zero-energy homes (ZEHs) in the western grid. Although minimized via utilization of advanced building technologies, ZEHs still consume energy that must be balanced on an annual basis via self-generation of electricity which is commonly assumed to be from rooftop photovoltaics (PV). This results in a ZEH having a significantly different electricity demand profile than a conventional home.

Wide-spread implementation of ZEHs will cause absolute demand levels to fall compared to continued use of more conventional facilities; however, the shape of the demand profile will also change significantly. Demand profile changes will lead to changes in the hourly value of electric generation. With significant penetration of ZEHs, it can be expected that ZEHs will face time of day rates or real time pricing that reflect the value of generation and use. This will impact the economics of ZEHs and the optimal design of PV systems for subsequent ZEHs.

Introduction

The development and wide-scale implementation of net zero-energy buildings (ZEBs) and net zero-energy homes (ZEHs) would, in practice, result in a significant reduction and shift in annual energy consumption. Although minimized via utilization of advanced building technologies, net zero-energy facilities still consume energy that must be balanced on an annual basis via self-generation of electricity. The self-generation technology of choice is commonly presumed to be rooftop photovoltaics (PV), and that is assumed to be the only on-site generating source for this study. Furthermore, it is assumed herein that ZEHs are all-electric. Hence, for any hour of the year, the ZEH may be either a net user or net generator of electricity; but, over an entire year the ZEH will show zero energy consumption or generation on the electric meter.

The net zero-energy facility, as seen by the grid, will obviously have a significantly different electricity demand profile than a conventional facility. Depending on the timing of net demand or net generation and the variability of hourly electricity rates, a net zero-energy facility with "net-metering[1]" may have a net electricity cost or credit. Wide-spread implementation of net zero-energy facilities would significantly change the load profiles that the grid must serve. Absolute demand levels would fall compared to continued use of more conventional facilities, but the shape of the demand profile could also change significantly. Existing peaks may be flattened. New peaks may be created. Either or both of these results could lead to changes in electric rates that affect the economics of net zero-energy facilities and the optimal design of PV systems for subsequent net zero-energy facilities. This exploratory study focused exclusively on net zero-energy homes and attempted to answer the following questions:

[1] Net-metering is an energy purchase/sales arrangement wherein the customer/generator buys or sells energy at the same price, which can vary by hour, day, or season. Thus, because the value of energy varies, a net-zero energy facility will not necessarily be a net-zero energy-cost facility.

- What is the expected net electricity demand profile for a ZEH? How does this compare to the demand profiles of conventional and highly efficient homes? (A highly efficient home is assumed to be of the same design as a ZEH but with no PV panels.)
- How might widespread implementation of net zero-energy facilities affect the utility electricity demand profile?
- How might changes in the utility electricity demand profile likely affect electricity rates?
- How might changes in electricity rates affect net electricity costs for the net zero-energy facilities creating the change in utility electricity demand?
- How might changes in electricity rates affect PV system design for subsequent net zero-energy facilities?
- Will widespread adoption of ZEBs without consideration of their impact beyond the building lead to suboptimal results?

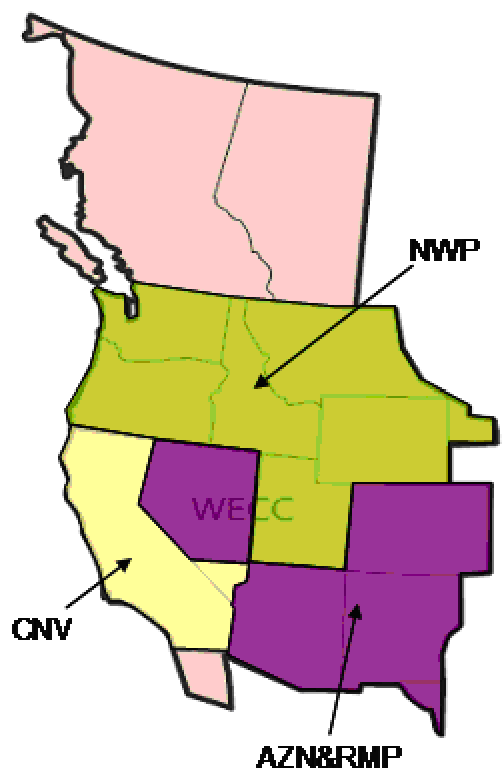
Approach

To answer these questions a subsection of the country was considered that offers good diversity of insolation and temperatures. A simulation model was run to determine the ZEH loads that would need to be met through generation. Then a number of different PV system designs were generated for each climate area within each sub-region and the implications of those designs on the system capital cost and the value of energy produced was considered. Finally, the impact of ZEHs on the grid was investigated.

It is assumed throughout that as ZEH penetration within the market becomes more pronounced that utilities will require ZEHs to pay the true cost of the energy they are provided and that they will be paid for the true cost of energy that they produce. Hence, utilities and ZEH owners will desire the same PV system designs—those that maximize the energy value while minimizing the capital cost.

Because this analytical work was exploratory, our general approach favored being selective and thorough over being comprehensive and cursory. As such, the scope of this study was limited to homes in three sub-regional power grids that are located within the United States and defined in Kintner-Meyer et al. (Kintner-Meyer, Schneider & Pratt 2007): Northwest Power Pool Area (NWP), California and Southern Nevada Power Area (CNV), Arizona-New Mexico-Nevada Power Area and the Rocky Mountain Power Area (AZN&RMP). The WEEC sub-regions are shown in Figure 1.

Figure 1. WEEC Sub-Regions



These three regions were selected to cover a broad range of climate and utility characteristics in the United States. The key characteristics of the load profiles for these three regions are summarized in Table 1.

Table 1. Key Characteristic of WEEC Sub-Regions

Characteristic	NWP	CNV	AZN&RMP
Peak Season/Humidity	Winter/Dry	Summer/Dry	Summer/Dry
insolation	moderate (~4.5 kWh/m^2/day)	good (~5.7 kWh/m^2/day)	excellent (~6.1 kWh/m^2/day)
Summer day average peak v. summer baseload	~ 45% higher than summer day average minimum	~ 55% higher than summer day average minimum	~ 65% higher than summer day average minimum
Winter day average peak v. winter baseload	~ 40% over winter day average minimum (morning & evening)	~ 50% over winter day average minimum	~ 35% over winter day average minimum
Summer v. winter baseload	Winter about 10% greater than summer	Summer about 10% greater than winter	Summer about 15% greater than winter
Summer v. winter average peak	Winter day ~ 5% greater than summer	Summer day ~ 15% greater than winter	Summer day ~ 45% greater than winter
Summer v. winter peak hour	Winter ~ 5% greater than summer peak	Summer ~ 30% greater than winter	Summer ~ 40% greater than winter

This investigation drew heavily upon two recently-completed analyses: ZEH characteristics were taken from the *Lost Opportunities Analysis* (Dirks, Anderson, Hostick, Belzer & Cort 2008), and electricity demand profiles were taken from *Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids* (Kintner-Meyer, Schneider & Pratt 2007). Characteristics of ZEHs used in this analysis are shown in Table 2.

Table 2. Characteristics of ZEHs and Highly Efficient Homes

Characteristic	Value
Conditioned Floor Area (ft^2)	2282
Window U-Value (Btu/h•ft^2•°F)	0.05
Window Shading Coefficient (North/South)	0.7/0.2
Wall Total R-Value (h•ft^2•°F/Btu)	40
Roof Total R-Value (h•ft^2•°F/Btu)	50
Floor Total R-Value (h•ft^2•°F/Btu)	50
Infiltration/ventilation (Air Changes per Hour)	0.35
Average Lighting Efficacy (lm/W)	90
Heat Pump Cooling—Seasonal Energy Efficiency Ratio (SEER)	25
Heat Pump Heating—Heating Seasonal Performance Factor (HSPF)	13
Heat Pump Water Heater—Energy Factor (EF)	3

The characteristics listed in Table 2 are quite aggressive and many of the values are unobtainable with current technology. However, under a scenario of high ZEH penetration, it is believed that the cost trade-off between greater efficiency and more PV will favor aggressive reductions in consumption over increased generation. With significant R&D being expended by DOE and others to reduce energy consumption it can be expected that technologies meeting these goals would be available in the 10 to 15 year timeframe. Additionally, while not varied or optimized for the different climates (other than the shading coefficient), a home with the characteristic of Table 2 would be extremely efficient in any climate.

Climate, NERC Sub-Region and City Selection

There are 15 International Energy Conservation Code (IECC) climates zones (International Code Council 2005) that are widely used for energy studies, as shown in Figure 2. Within each of the three WECC sub-regions modeled, there are seven or eight climate zones. Some climate zones represent only a very small fraction of the total population for a sub-region; those climates (totaling less than 3 percent of the population in any region) were not modeled because the impact of excluding those climate zones from the total sub-region loads was negligible. Total loads were scaled to account for the population in the unrepresented climate zones. Table 3 shows the city selected to represent each climate zone in each sub-region modeled.

Figure 2. International Energy Conservation Code Climates Zones

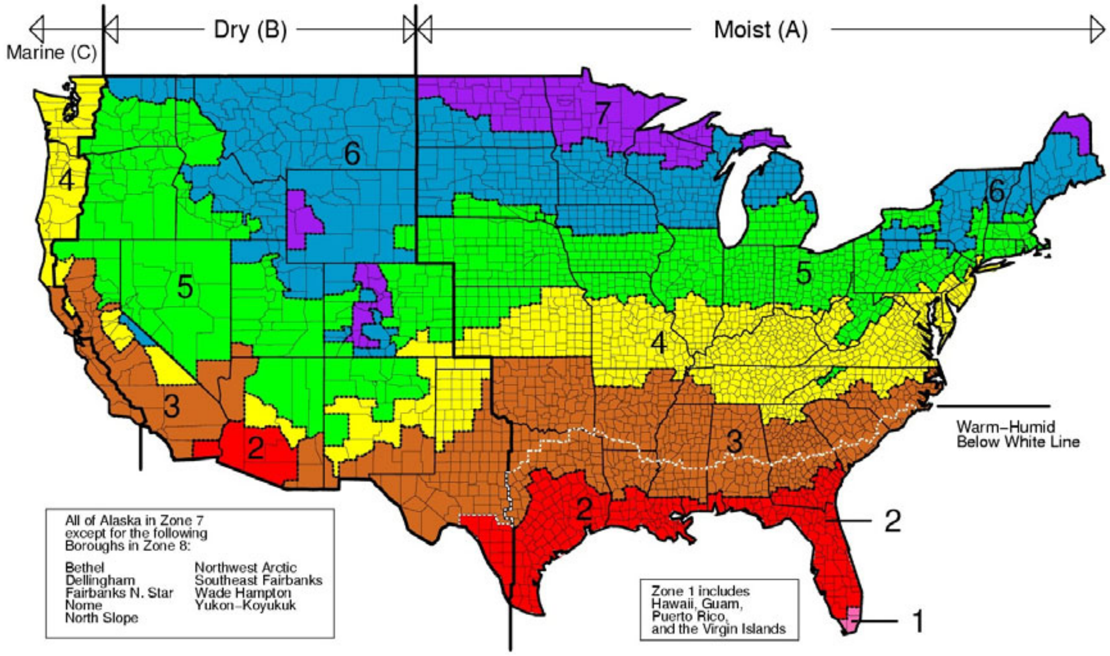


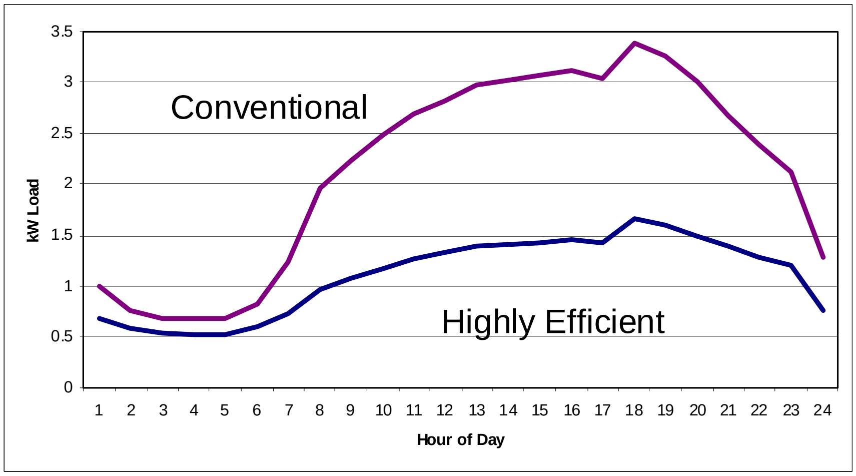
Table 3. City Selected to Represent Each Modeled Climate Zone.

AZN&RMP	CNV	NWP
Albuquerque (Zone 4_dry)	Fresno (Zone 3_dry)	Helena (Zone 6_dry)
Boulder (Zone 5_dry)	Los Angeles (Zone 3_dry)	Salt Lake (Zone 5_dry)
El Paso (Zone 3_dry)	San Francisco (Zone 3_marine)	Seattle (Zone 4_marine)
Phoenix (Zone 2_dry)		

Profiles

The Facility Energy Decision System (FEDS) software (Dahowski & Dirks 2008) was used to simulate building performance and generate building level consumption profiles. Example profiles for highly efficient and conventional homes in Fresno on an average day in July are shown below in Figure 3.

Figure 3. Load Profiles for Conventional and Highly Efficient Homes in Fresno



Notice how much smaller and flatter the load profile is for the highly efficiency home (average daily consumption is ~26kWh and the difference between the minimum and maximum hourly loads is ~1.2 kW). Dividing the difference between the maximum and minimum hourly loads by the minimum hourly load gives us a relative measure of the peakiness[2] of the load; in the case of the highly efficient home, this value is 225%. For the conventional home load profile average daily consumption is nearly twice that of the highly efficiency home at ~51kWh and the difference between the minimum and maximum hourly loads is ~2.7 kW. Hence, the conventional home is much more peaky with a relative peakiness of 402%.

For this high-efficiency Fresno house to be net-zero annually, it would need a PV array nominally rated at 6.43 kW with a net derated[3] capacity of 4.95 kW. The output of this array for an average day in July is shown in Figure 4.

Combining the load and the generation yields a net load profile for the ZEH on an average July day as shown in Figure 5. The ZEH is a net consumer from about 5 pm to 7 am, and during the net generation time (7 am to 5 pm), the output is much greater than the consumption when not generating making the average July day a net generation day of just over 6 kWh. The ZEH has a very large difference between the minimum and maximum hourly loads (~4.5 kW) when compared to the conventional or highly efficient home. The measure of relative load peakiness is not defined because of the generation; however, the 4.5 kW difference between the minimum and maximum hourly loads could potentially present the utility company with difficulties as we will investigate below.

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[2] Peakiness is defined as the difference between the maximum and minimum hourly loads divided by the minimum hourly load.
[3] The overall DC to AC derate factor used for all PV array in the analysis was 77%.

Figure 4. Fresno July Average Day—Net Zero PV Array Output

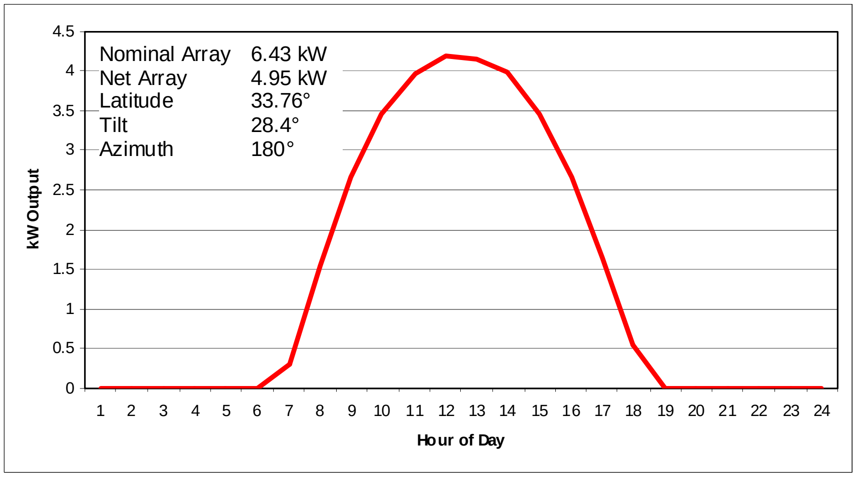
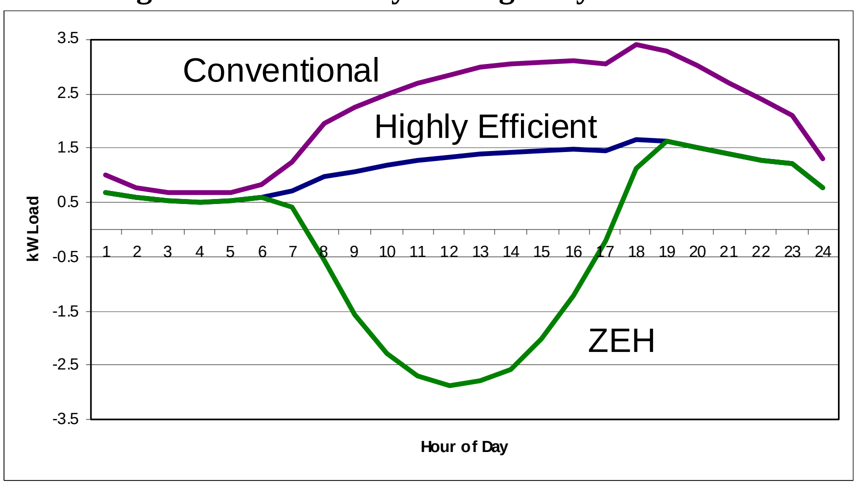


Figure 5. Fresno July Average Day—Net Load



PV System Design

In order to minimize PV system costs for ZEBs or ZEHs, the PV system is generally oriented to maximize its annual output. Given the significant expense of PV systems, it often makes sense to try to maximize annual output, thus lowering the cost per kWh of production (average production cost equal the sum of annualized capital and O&M costs divided by the annual output). Additionally, residential consumers, who rarely have time-dependent rates, have no incentive to do anything but orient their array to maximize annual output. In contrast, medium to large commercial customers often have time-of-day rates and demand charges, so designing to maximize output may not represent a minimum life-cycle cost design (where life-cycle cost is defined as the annualized cost of the array less the annualized value of the energy produced realized by the building owner). Designing the system to maximize output during a season or at a particular time on a particular day may in fact be more cost-effective.

Hourly performance of all PV system designs was calculated using PVWATTS Version 1 (NREL 2010a). As part of all the designs, the default "Overall DC to AC Derate Factor" of 77% was used (NREL 2010b). For all homes in this analysis the array was sized to whatever was required to achieve net-zero without regard to the actual amount of available roof area or its orientation. (Most ZEHs will be new construction allowing for the proper roof slope and orientation.) For each of the ten cities, at least four PV systems were designed: maximize annual output, maximize July output, maximize January output, and maximize output on the system peak hour for the WECC or a sub-region.

Traditionally it is assumed that the maximum annual output design has the array pointed due south and the panel tilt is equal to the latitude (Tilt—0° is horizontal and 90° is vertical). This would in fact be the case if the number of hours of insolation in the summer and winter were the same; because this is not the case (substantially more daylight hours in the summer as compared to winter), the optimal tilt to maximize annual output is considerably more horizontal. Table 4 provides both the latitude and optimal tilt angle for each city (determined through iterative designs), assuming an azimuth of 180° (due south). As the table illustrates, in some locations the latitude is a reasonably good proxy for the tilt that maximizes the annual output (e.g., El Paso) and in other cases where it is not (e.g., Seattle). For situations like Seattle, where there is a pronounced difference between the latitude and the optimal tilt, it is caused by significantly greater cloud cover in the winter than in the summer. Hence, a simple simulation is recommended rather than following the "tilt at the latitude" rule-of-thumb.

Table 4. Tilt Angles of South Facing Array That Maximize Desired Output

City	Latitude (°N)	Tilt (°) for Maximizing Annual Output	Tilt (°) for Maximizing July Output	Tilt (°) for Maximizing January Output
Albuquerque	35.05	33.7	9.0	62.0
Boulder	40.02	37.8	13.5	64.5
El Paso	31.80	30.9	4.5	59.0
Phoenix	33.43	31.6	6.5	61.0
Fresno	36.77	28.4	10.5	54.0
Los Angeles	33.93	32.1	7.5	57.0
San Francisco	37.62	30.9	12.5	59.0
Helena	46.60	39.5	15.5	66.5
Salt Lake	40.77	35.3	10.5	60.0
Seattle	47.45	33.6	21.0	57.0

Recognizing that the WECC is summer-peaking, it was thought that the value of energy to the utility (or owner under time-of-day rates or real time pricing) would be significantly greater in the summer and hence, that the minimum life-cycle cost system under time-of-day rates might be achieved by maximizing the output in July rather than trying to maximize the annual output. It was also recognized that the NWP sub-region is winter-peaking, and that for this sub-region designs that maximize winter output may be the minimum life-cycle cost designs.

Continuing this logic, and recognizing that the peak value of energy within the WECC is likely to occur simultaneously with the peak demand for energy, PV systems were designed to maximize output on the peak system demand hour. In these designs, shown in Table 5, the PV arrays are positioned such that the panels are orthogonal to the solar beam at the peak demand hour. Notice that most of the arrays for the cities in the southern portion of the WECC are pointed nearly due west.

Table 5. Tilt and Azimuth Angles to Maximize Output at WECC Peak Hour

City	Latitude (°N)	Tilt (°)	Azimuth (°)
Albuquerque	35.05	44.9	267.3
Boulder	40.02	46.4	263.3
El Paso	31.80	45.0	270.6
Phoenix	33.43	40.3	265.7
Fresno	36.77	46.5	266.8
Los Angeles	33.93	47.5	270.2
San Francisco	37.62	44.5	264.2
Helena	46.60	43.0	251.1
Salt Lake	40.77	41.5	257.3
Seattle	47.45	46.3	254.7

How the utility values energy it sells and buys from ZEHs determines what the minimum life-cycle cost design of the PV system would be. Hence, another possible design that could be the minimum life-cycle cost is to maximize the output for the hour of peak building demand.

Albuquerque designs. The AZN&RMP sub-region, like the WECC itself, is summer-peaking. Therefore, PV system designs that maximize output during the summer may produce energy of greater total value than designs that maximize annual output. Following are four possible minimum life-cycle cost designs for Albuquerque, all of them designed for the same total annual output: minimize array size, maximize July generation, maximize output at hour of system peak demand (July 10th at 15:30; azimuth = 267.3°, tilt = 44.9°), and maximize output at hour of building peak demand (August 16th at 17:30; azimuth = 275.4°, tilt = 74.3°). There are several things to notice about these four designs and associated hourly output:

- All the designs provide the same annual output with a different distribution diurnally and across months.
- The minimum ZEH capacity design is the traditional PV design that maximizes annual energy output per unit of capacity and is the appropriate design for flat rates and net-metering.
- All other designs increase the required array size to achieve the same annual output.
- Designs that attempt to maximize production for a particular hour of the year have highly asymmetrical output over a day.

To further understand the implications of the design differences, Figure 6 shows the July average hourly production for each of the four designs and Figure 7 shows the net load for each design. Both charts include the average hourly building load. Figure 8 shows the monthly generation for various net zero array designs.

Figure 6. July Average Hourly Output for Array Design Option

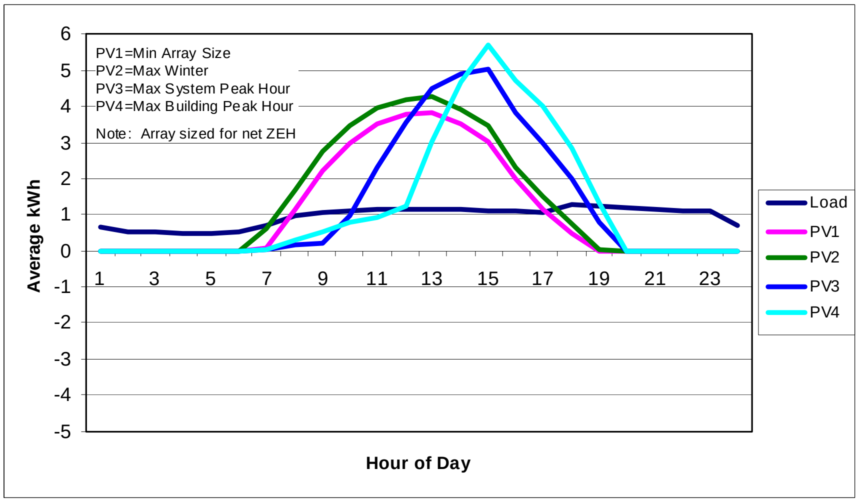


Figure 7. July Average Hourly ZEH Net Load for Array Design Option

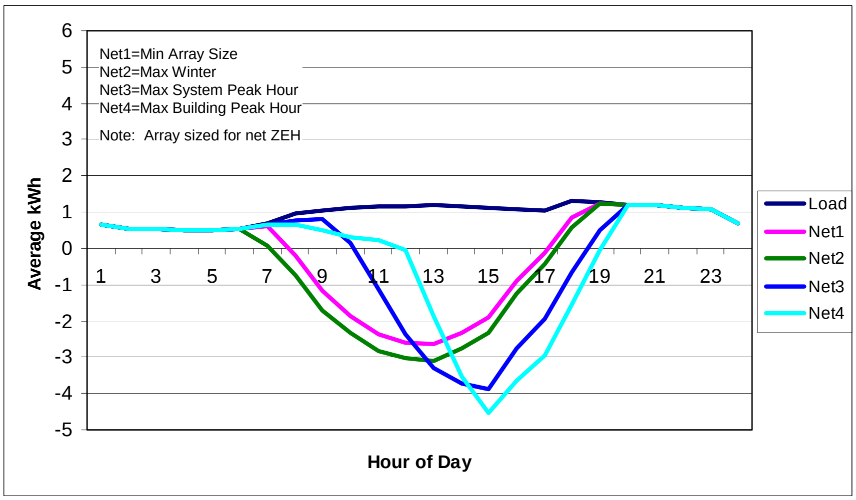
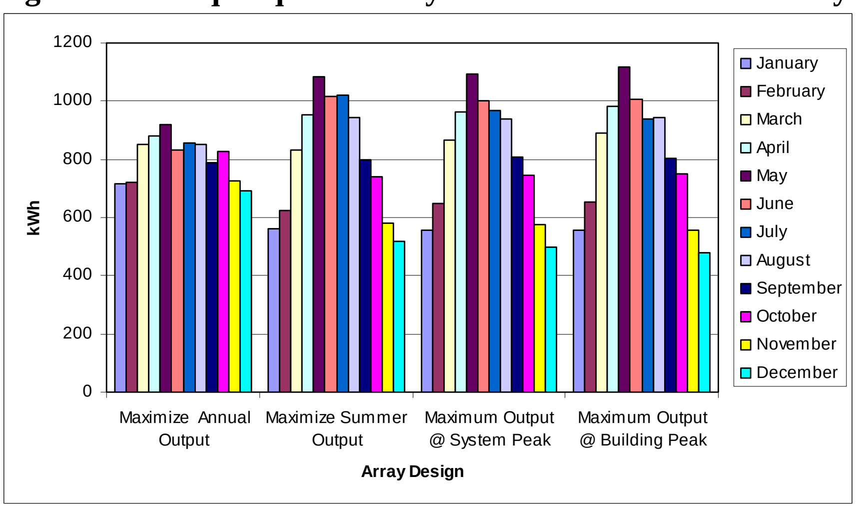


Figure 8. Albuquerque Monthly Generation—Net Zero Arrays

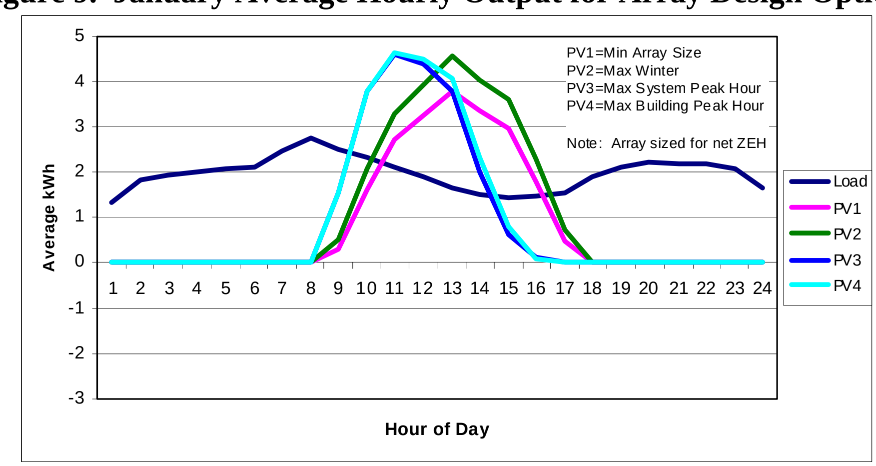


As is obvious from the difference in the average hourly output for July, the system design objective significantly impacts the PV array performance for any particular hour. These differences in performance extend beyond just hourly variations, with pronounced monthly variations as well. In the Figure 8 below notice how, under the design that maximizes annual output, that the May output is less than 25% more that the December output, but that in all the other designs, the May output is over twice that of the December output.

Helena designs. In the NWP, a winter-peaking sub-region of the WECC, PV system designs that maximize output during the winter may produce energy of greater total value than designs that maximize annual output. Following are average hourly output plots for each month of the year, for four possible minimum life-cycle cost design strategies for a home in Helena MT (part of the NWP): minimize array size, maximize January generation, maximize output at hour of NWP sub-region peak demand (January 29th at 7:30—note that the peak occurs prior to sunrise so the system is designed to maximize output at sunrise; azimuth = 117.3°, tilt = 90°), and maximize output at hour of building peak demand (January 16th at 7:30—note that the peak occurs prior to sunrise so the system is designed to maximize output at sunrise; azimuth = 121.6°, tilt = 90°).

The four bullets above that described the differences in the Albuquerque designs are also valid for the Helena designs. Similarly, Figure 9 shows the January average hourly production for each of the four designs and Figure 10 shows the net load for each design. Both charts include the average hourly building load.

Figure 9. January Average Hourly Output for Array Design Options



As shown below in Figure 11, there are some significant differences between the Albuquerque designs and the Helena designs. Notice that while the Albuquerque maximize annual output design has a less than 25% variation between May and December, for the Helena design, the July output is 2.5 times the December output. This is because the summer days in Helena are long and sunny, while the winter days are short and cloudier; hence, the array is positioned to take advantage of the long summer days. Conversely, the design that maximizes winter output has a much less pronounced difference, with the peak generation month actually being March, and December, providing only 42% less output than July.

Figure 10. January Average Hourly Net Load for Array Design Options

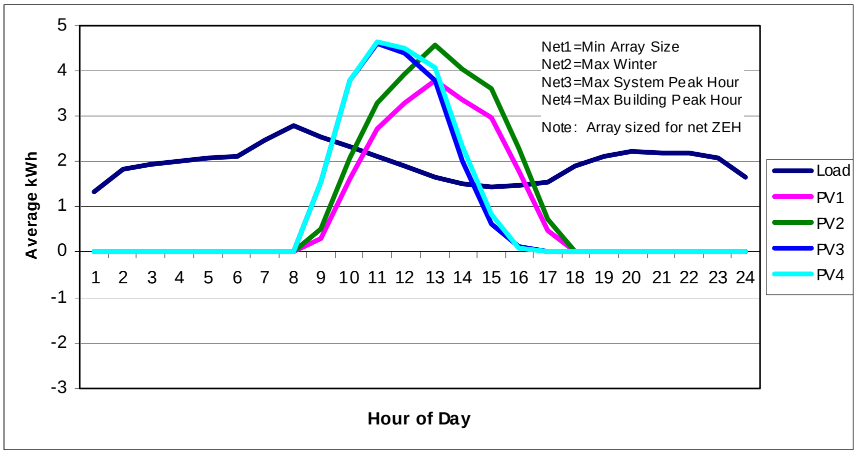
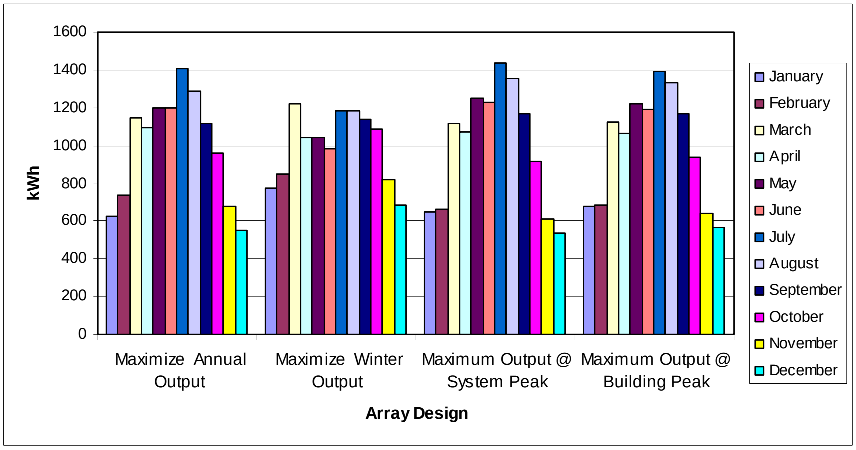


Figure 11. Helena Monthly Generation—Net Zero Arrays



Cost Impacts of Designs

Any design that does not maximize the annual output will necessarily require a greater array size to achieve the same annual output. The capital cost impact can range from moderate to severe depending on the design intent. For example, the Table 6 shows the July (when peak demands occur in the WECC) and annual energy production for arrays designed to maximize annual output and to maximize July output for selected cities in summer-peaking sub-regions. These data illustrate the range of impact between designs that maximize July output relative to the designs that maximize annual output. For any particular location the annual output is the same for either design; however, the July maximizing designs have July outputs that are 18% to 21% greater than the annual output maximizing designs, at a capital cost premium of only 8% to 10%. If one was in a summer-peaking area with time-of-day or real-time pricing, a July maximizing design may be a substantially more cost-effective array design than designing to maximize annual output.

Table 6. Impact of Summer Max Designs on Cost and Performance

Design	Boulder		Albuquerque		El Paso		Phoenix	
	July	Annual	July	Annual	July	Annual	July	Annual
Annual Max (kWh)	917.4	10494.8	858.8	9666.8	760.2	9009.8	806.8	9070.6
Summer Max (kWh)	1086.5	10494.8	1020.2	9666.8	918.5	9009.8	951.7	9070.6
Percentage Change	18.4%	0.0%	18.8%	0.0%	20.8%	0.0%	18.0%	0.0%
Increase in Cost	8.0%		8.4%		9.8%		8.9%	

The amplitude variation in the hourly cost/value of energy under time-of-day or real-time pricing can be so extreme (up to 2 orders of magnitude difference in the value of energy—what the utility will pay generators—between the minimum and maximum value hours) that one must consider designs that will maximize output at the time when the grid demand and energy value are peaking. Table 7 shows the July and annual energy production for arrays designed to maximize annual output (AM designs) and to maximize output at the WECC system peak (SP designs) for selected cities in summer-peaking sub-regions that illustrate the range of impact of SP designs relative to AP designs.

Table 7. Impact of Max System Peak Designs on Cost and Performance

Design	Boulder		Fresno		Phoenix		San Francisco	
	July	Annual	July	Annual	July	Annual	July	Annual
Annual Max (kWh)	917.4	10494.8	1011.6	9401.4	806.8	9070.6	957.8	9734.3
System Peak (kWh)	1025.8	10494.8	1153.5	9401.4	978.0	9070.6	1273.8	9734.3
Percentage Change in kWh	11.8%	0.0%	14.0%	0.0%	21.2 %	0.0%	33.0%	0.0%
Annual Max (kW) July 3 pm - 4 pm	1.98		2.67		2.54		2.57	
System Peak (kW) July 3 pm – 4 pm	4.01		5.20		4.46		5.79	
Percentage Change in kW	102.3%		94.9%		75.4%		125.3%	
Increase in Cost	42.8%		30.6%		28.3 %		26.6%	

Additionally the table shows the average output from 3 pm to 4 pm in July[4] for the AM and SP designs. For any particular location, the annual output is the same for either design; however, the SP designs have July outputs that are 12% to 33% greater than the AM designs, at a

[4] Rather than use a single hour of a single day, the average is shown for the month so that information would be representative of actual designs rather than a particular instance in time. For example, the WECC is likely to peak in the afternoon in July every year; however, it will not peak at 3:30 pm July 10th every year, and the weather in every location every year will not be the same as on July 10th of the design year.

cost premium of 27% to 43%, which is a substantially greater cost premium than was previously shown for designs that maximized July output. Is the cost premium worth it? It may be if one was in a summer-peaking area with time-of-day or real-time pricing. Notice that the production during the highest value hours is from 75% to 125% greater with the SP design compared to the AM design. A careful evaluation of the annual value of the energy produced (i.e., what the utility would pay for energy produced) would need to be conducted prior to selecting the array design if one wants the minimum life-cycle cost system for a ZEH.

Rate and Capacity Impacts

The original plan was to use PROMOD IV (Ventyx 2009) to test several hypotheses regarding PV system design and the value of the energy generated to determine minimum life-cycle cost designs for building-level PV systems. PROMOD IV is a generator dispatch and portfolio modeling system capable of modeling all the generating and transmission capacity within the grid, and optimally dispatching that capacity such that the entire load is met at the minimum life-cycle cost. The general hypotheses were to be investigated under the assumption of 100% penetration of ZEHs to answer the questions regarding how widespread implementation of ZEHs would affect the utility electricity demand profile. The specific hypotheses were:

- Reducing the peak demand is good—reduces required capacity and reduces the utilization of high heat rate units
- Narrowing the peak is indeterminate—capacity is not reduced, energy is reduced in high heat rate units, utilization of equipment is reduced resulting in additional allocated costs per unit of energy produced during the peak, environmental impacts could go either way
- Increasing the depth of the valley is bad and good—causes baseload plants (low heat rates and high capacity utilization) to be replaced by intermediate and peaking plants with high heat rates and lower capacity utilization, if baseload is coal, environmental impacts are likely to be positive and if it is not coal (e.g., nuclear or gas), then the environmental impacts are likely to be negative

The results of the analysis indicated that full ZEH penetration in the WECC was a mixture of good and bad news. The good news, shown in Figure 12 below, is that for 4 typical summer days (June 29th to July 2nd), the peak demand was reduced by a range of 22% to 27% and the peak was pushed out from 1 to 5 hours[5] depending on the design. The bad news is that, for several days, the net demand on the system was negative, which caused PROMOD IV to crash. At this point, the PROMOD approach was abandoned for a more subjective graphical approach based only on these four days.

Recognizing that full penetration is impractical, even as an intellectual exercise, a lower level of penetration, where the baseload demand would be disrupted to only a minimal extent, was investigated as shown in Figure 13. For the 4 days shown above, July 1st at ~7 am was the minimum demand level without any ZEHs. Given that PV production is minimal at 7 am, a reasonable ZEH fraction (i.e., one that would not disrupt the grid by idling baseload power plants and increasing the use of more expensive intermediate and peak-load plants) was deemed to be the level at which midday demand (when PV production is at its peak) was reduced to the 7 am

[5] The typical peaking plant is a simple cycle gas turbine. If the peak is pushed out to later in the day (when the temperatures are cooler), the gas turbines will operate more efficiently.

level for the SP design. The penetration rate for the AM design was then set to the value that would achieve this same minimum baseload capacity. This resulted in a penetration rate of 28.5% for the SP design and 19.9% for the AM design. As shown in Figure 13, the SP design yields a peak reduction ranging from 10% to 13% and the peak was pushed out from 3 to 5 hours, while the AM design resulted in a peak reduction ranging from 6% to 8% and the peak was pushed out from 1 to 2 hours.

Figure 12. WECC Power Demand June 29 to July 2: 100% ZEH Penetration

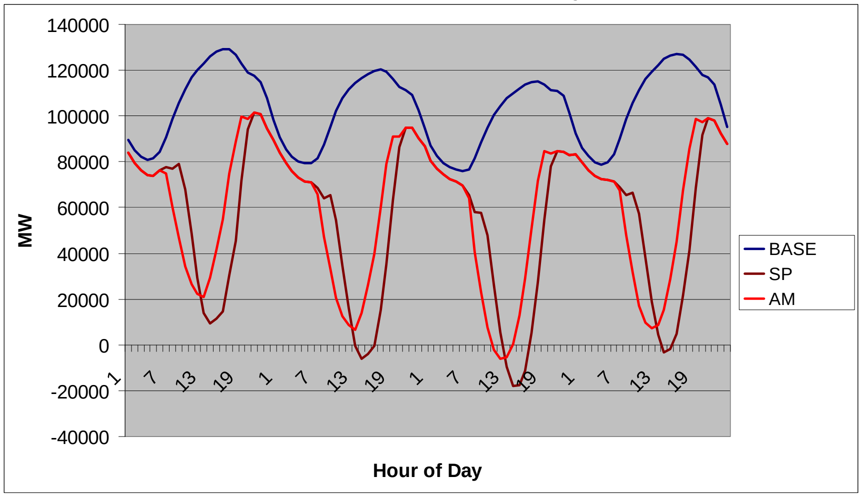
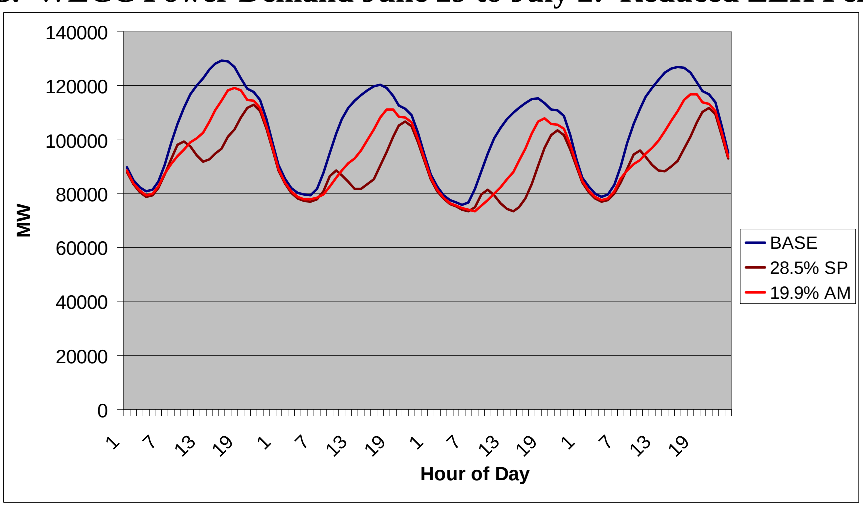


Figure 13. WECC Power Demand June 29 to July 2: Reduced ZEH Penetration



Based on this analysis, some conjecture regarding the unanswered questions can now be offered. Given that baseload power is less expensive to produce than intermediate load power, and intermediate load less expensive than peaking, anything that makes the aggregate demand profile peakier will likely increase the cost of electricity and hence increase electric rates. Hours with the lowest levels of aggregate demand will have the lowest cost/price/value and the converse is also true. Hence, as the number of PV installations grow, and the midday value of energy falls, the aggregate value of the energy produced (i.e., what the utility is willing to pay the producer) will decrease and hence, the cost-effectiveness of PV will decrease. This is similar to what is already happening in the Northwest with wind power, where the concern is that "when it's windy in the Northwest, big blocks of electricity could flow onto the grid with no contracted customer. In extreme events, that can force operators to pay customers to take the electricity." (Oliver 2009) Hence, the "value" of wind generation at that moment is negative. This problem is not restricted to the Northwest. For the West region of ERCOT, "in the first half of 2008, prices were below zero nearly 20 percent of the time." (Gilberson 2008)

As rates change in response to increase PV generation, designing to maximize output at the system peak (where the value and demand is greatest) rather than designing to maximize annual generation permits a significantly greater ZEH penetration rate before the baseload demand is impacted (28.5% versus 19.9%). Additionally, significant PV penetration pushes out the time when the peak occurs; hence, the value of power will peak later in the day and designs that produce more power later in the day will have higher value. There is a limit however. In the 100% penetration graphic, it is obvious that under that scenario, the peak would occur after PV production went to zero. Therefore, some form of electrical energy storage would seem to be required for greater levels of PV penetration if you do not want to disrupt the baseload.

Conclusions

- Surprisingly low penetration rates of ZEHs will have significant impacts on the grid by displacing flat loads that are served by baseload plants with highly varying loads that must be served by more expensive peaking and intermediate load plants. Penetration rates of greater than 20% (assuming AM designs, which are the conventional approach) will begin to seriously impact the grid, and this assumes zero penetration of ZEBs and no new additions of standalone PV generation. If one assumes that there is also significant penetration of ZEBs the problem will get worse not better. Improved energy efficiency in buildings flattens the load—it is the PV generation that make the net load so peaky.
- Utilities like flat loads. Highly efficient homes have a flatter load profile than conventional homes. The load profile for ZEHs is extremely peaky and hence, undesirable from a utility perspective.
- Widespread adoption of ZEBs without consideration of their impact beyond the building will almost certainly lead to suboptimal results. If everyone designs their arrays to maximize annual energy production, the results will be suboptimal. One must consider the value of the energy being produced when designing an array if your goal is to be net-zero *and* cost-effective.
- A careful evaluation of the value of annual energy produced would need to be conducted prior to selecting the array design if one wants the minimum life-cycle cost system.
- Utilities will change rates at which they purchase energy when PV penetration begins to impact grid operation. As PV penetration begins to impact rates, the cost optimal array orientation will change.
- From Figure 5 one can infer that a distribution system serving a subdivision of highly efficient homes in Fresno would need to be able to handle a load of about 1.7 kW per house. A distribution system serving a similar subdivision of ZEHs would need to be able to handle about 2.9 kW of load per house (net generation), which would require a 70% larger distribution system.
- In order to minimize the disruptions to the grid that would be accompanied by a significant level of PV penetration (as a result of high ZEH penetrations) it would be

highly desirable to be able to match a load to the time of peak PV generation. As discussed above flat loads are less costly to serve than peaky loads. Additionally, if the generation peaks of a PV system mounted on a ZEH could be kept from flowing back to the grid it would allow for nearly unlimited penetration of ZEHs. Employing some combination of thermal energy storage, thermal mass and possibly pre-cooling, phase change materials, and active storage (chilled water or ice) offer significant opportunities to use PV generated electricity as it is generated (to charge the storage) thereby decreasing flows back onto the grid.

- Even with thermal energy storage, some form of electrical energy storage will be required to balance the generation and demand if we are going to be able to have significant levels of PV/ZEH penetration. The closer to the generation source the storage is provided, the lower the impact of high PV/ZEH penetration rates on the gird. Stationary storage at the home or wide spread use of plug-in hybrid electric vehicles (PHEVs) may provide adequate storage capacity without the need for significant utility level investment.

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