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Suggested changes to Rule 21 – Renewable Fuels and AB 1969 – Feed-In Tariff

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I have read the “California Feed-in Tariff and Policy Options” report prepared November, 2008 for the California Energy Commission by KEMA, Inc. I concur with most of the recommendations and conclusions. I have also reviewed the documents on the Interstate Renewable Energy Council (IREC) website, www.irecusa.org. Some points that I would emphasize, clarify or add to are as follows:

DESIRED OUTCOMES OF ALL CHANGES

1 Stimulate short and long-term economy and job gains.
2 Move the USA and CA energy sector toward domestic self-sufficiency.
3 Encourage maximum energy conservation and efficiency.
4 Expedite adoption of Renewable Power Generation (RPG).
5 Meet the goals of AB 32, Renewable Portfolio Standards (RPS) and AB 1969.
6 Embrace Distributed Generation (DG) as a highly desirable method of meeting local energy loads without incurring the high environmental and economic costs of high voltage grid transmission and centralized generation.
7 Diversification of fuel types for RPG is good, stabilizing the market, power generation and costs.
8 Overshooting the goals of RPS, AB 32 and AB 1969 is better than under achieving them.

OVERARCHING RECOMMENDATION

It is becoming apparent that it is desirable to simplify the current programs by melding Rule 21 and AB 1969 into one working program. Many states and other countries are doing this and they can be used as a resource as to how this might be done. Appropriate suggested changes under “Specific Recommendations” for Rule 21 and AB 1969 should still be made for this hybrid program. Some of the benefits of this hybrid program are;

1. IOU’s (Investor Owned Utility), POU’s (Publically Owned Utilities), ERR (Eligible Renewable Energy Resource), government workers and regulators and others would be better able to understand, promote and not confuse the two existing programs.
2. There would not be conflicts and limitations as there are now between the two programs.
3. As new renewable technologies are developed, integration would be simplified.
4. Administration of AB 32, RPS and RPG goals would be simplified.
5. All renewable fuels, as defined in PRC 25741 and PUC 399.11 Decision 03-06-071 should be included.
6. ERRs would not have to understand and decide which is best for their needs now and in the future. If, in the future, the ERR started producing or reducing excess power, then there would be no need to change anything.
7. Time Of Day (TOD) Net Metering (TOD-NEM) would be the only meter required. This would simplify design, procurement and replacement.
8. All IOU, POU, and ERR meters should be able to be remotely monitored and read wirelessly
9. The TOD-NEM meter would be sized by the service capacity. Importation and exportation would be seam-less and limited by this capacity. This would allow additions and deletions of generation and/or load without changes to the contract, wiring, connection or metering.
10. ERRs should not be required to feed all generated power back to the main service panel, but should be able to use the same subpanels and wires used for the connected load. The standard should be the Institute of Electric and Electronics Engineers (IEEE) Standard # 1547, UL 1741 or the IREC

(2007) “Interconnection Standards for Distributed Generation Model”. This would save rewiring costs, material costs and resources.

11. Successful programs use the 12 month roll-forward method. This is similar to the existing Net Meter annualized true-up program except that it is always rolled forward by one month with payment for the used or produced power every month after the 12th month. This would simplify billing, smooth out payments and/or income for both the IOU and the ERR.
12. Very few loads and renewable generators can be balanced on a month-to-month or even quarter-to-quarter basis. Using #11 would make this unimportant. Grid stability and capacity would be increased and supplied by the diversity of the ERRs and their ability to smoothly import or export power.
13. ERRs should be required to report to the IOU’s and POU’s total renewable energy production. This can be done annually, semi-annually or quarterly. This report would be used to determine progress towards the goals, Renewable Energy Credits (RECs) and for renewable electricity production tax incentive purposes. These meters can be separate meters or on the generator panel(s) to show net production. Parasitic loads from the generator should not be included in these production numbers.
14. ERRs would be encouraged to fully develop their renewable resource(s). Under existing Rule 21 renewable system design, annual output is limited or under-sized by annual on-site use.
15. ERRs would be encouraged to conserve energy because they could sell the excess and not make “use-it-or-lose-it” decisions. This would provide more renewable energy for other customers and encourage wise use of our resources.
16. The number and type of tariffs would be simplified. This would make administration, billing and changes simpler.

It is my opinion that the above program should be investigated and implemented immediately. In the interim or in lieu of this change, the following recommendations should be considered for Rule 21 and AB 1969.

SPECIFIC RECOMMENDATIONS FOR RULE 21/NET METER PROGRAM

1. All changes should be enacted immediately. This would help meet all outcomes.
2. All renewable fuels, as defined in PRC 25741 and PUC 399.11 Decision 03-06-071 should be included.
3. Biomass, other bio fuels and other forms of biogas should be considered the same as anaerobic biogas from dairy.
4. Rule 21 provisions should have a moving window of application for at least five years. This would automatically extend the program annually, for the next five years, and allow seamless expansion of RPS development. This is necessary for businesses, government, IOU’s and POU’s to do long term planning, expansions, improvements and R&D.
5. Make all target goals of AB 32, RPS and AB 1969 minimums. Consider penalties if they are not met by the IOU’s and POU’s.
6. Continue target goals of AB 32, RPS and AB 1969 beyond 2020. They need to be more aggressive and definitive, ie. 20% by 2010, 30% by 2015, 40% by 2020, 50% by 2025, 60% by 2030, 70 % by 2035 and 80% by 2040.
7. Move upper energy production limits by an ERR covered by Rule 21/Net Meter to 20 MW.
8. Remove the RPS cap for the state, IOU’s, POU’s and others. If these entities want to or the economy warrants going beyond the cap, they should be able to. ERRs need to know that they will not be cut-off from interconnection as we approach these caps.
9. “Must Take” provisions should stay in place for RPS and should apply to all IOU’s, POU’s and others.
10. Continue to provide a clear, simple up-front picture of costs and what needs to be done to complete the application and interconnection.
11. Continue to have clear cut or consistent requirements of what is required to interconnect. These requirements can be specified by using generation output brackets. These requirements should be the same for all IOU’s and POU’s, so that ERRs have consistent costs and requirements, no matter where they are located. The standard could be the Institute of Electric and Electronics Engineers

(IEEE) Standard # 1547, UL 1741 or the IREC (2007) “Interconnection Standards for Distributed Generation Model”.

12. External disconnect switches should not be required on systems less than 1.5MW.
13. Interconnection requirements should not be unreasonable, difficult or expensive. For example, ERRs should not be required to feed all generated power back to the main, but should be able to use the same subpanels and wires used for the connected load. This would save rewiring costs, material costs and resources.
14. The rules should be available to all ERRs so that they would not need to hire electrical engineers or consultants for each small project.
15. There needs to be means by which an ERR can object to excessive requirements. Excessive requirements will inhibit meeting the goals and RPG projects.
16. Establishment of an Information Clearinghouse, ERR Ombudsman and advocacy group is critical. This should cover all aspects of these projects and would include, but not be limited to; soil, water and air emission regulations, land-use regulations, fire and safety regulations, utility interconnections and available support funders.
17. If the maximum system size becomes 20 MW, than additional costs and fees, on a sliding scale, would be reasonable. Fees and costs shown ion IREC documents seem reasonable.
18. Increasing generation capacities of existing ERRs should be encouraged. This can be for the same or a different type of renewable power. Application and interconnection fees for these expansions should be ½ of the application fees for a new ERR or $500, whichever is lower. The logic behind this is that these ERRs already know the rules and requirements, the IOU’s and POU’s already are doing business with these ERRs and the likely follow-through and completion of this additional generation capacity is high.
19. If the proposed Renewable Distributed Generation (RDG) maximum output capacity from a ERR does not exceed the existing service capacity, then the fees, interconnection and meter costs should be minimal (less than $500) or none.
20. No departed load or stand-by charges.
21. RMPR (Renewable MPR, same as in FIT program) should be paid for exported power not used during the annual true-up if the IOU’s and POU’s do not meet RPS, AB 32 and AB 1969 goals, thus stimulating compliance.
22. IOU’s can only count inter-connected and operating ERRs toward meeting the goals of RPS and AB 32. No credit should be given for those ERRs that are not producing.
23. Clarify that ERRs that have received grants, funds or other incentives from various government and non-government programs are eligible to participate in the Rule 21/NEM program. The idea is that those programs would only incentivize emergent, speculative or R&D technologies or other needs such as GHG, energy and emissions reduction.
24. Accommodate the usage of different types of renewable generation on the same electrical service.
25. Federal tax credits (currently $.01/kWh Federal, only on power sold to a qualified IOU) (State too?) should be based on all renewable generation production, even that which is not interconnected and/or used on site of ERR. .
26. Tax credits for renewable energy generation should stay with the ERR.
27. All Green Attributes (including but not limited to; carbon and GHG credits or expenses stay with the ERR.
28. Renewable Energy Credits (REC) belong to the ERR.
29. IOU’s and POU’s can count energy produced by ERR, including electricity used on-site, towards meeting RPS, AB 32 and AB 1969 goals.
30. All meters should be TOD. This would encourage ERRs to maximize production and minimize use during TOD Peak Rates (times when CA needs power). This would reduce the need for peaker-plants and the high costs and emissions associated with them. The ability of ERR to produce power during these times is a benefit to all rate payers. The IOU’s and POU’s charge more for electricity used during these periods. ERRs should be rewarded for this.
31. TOD Net-Metering should be used on all renewable generation. All non-electric costs should be paid only on the purchased or imported power further stimulating renewable energy production.
32. TOD Net-metering should be available to all classes of ERR.
33. All ERR meters should be able to be remotely monitored and read.

17. Annual True-Up Periods should become rolling forward 12 month programs. This is similar to the existing Net Meter annualized true-up program except that it would always be rolled forward by one month with payment for the used power every month after the 12th month. This would simplify billing, smooth out payments and/or income for both the IOU and the ERR.
34. There are annual pay-out programs that allow an ERR to use net-metering over the course of the year and then pay for the power used or to be paid for the excess power produced. CA should transition to this type of program.
35. Peak power production rates should be higher than retail TOD purchase rates. This would be similar to Peaker Plant Rates and would encourage those ERRs that can produce exportable power during these peak periods to do so.
36. ERR's should be required to report to the IOU's and POU's total renewable energy production. This can be done annually, semi-annually or quarterly. This report would be used to determine progress towards the goals, RECs and for renewable production tax incentive purposes. These meters can be separate meters or on the generator panel to show net production. Parasitic loads from the generator should not be included in these numbers.
37. All ERR meters should be able to be remotely monitored and read wirelessly.
38. "Wheeling" of excess electricity production between service accounts on a customer's consolidated bill should be allowed. This allows ERR to efficiently produce power where the fuel is and use electricity where the load is, usually within a short distance. This is currently allowed with dairy bio-gas.
39. RMPR rates need to be set high at this point to encourage rapid RPG development in order to meet the AB 32 goals of 2010. This deadline is less than 2 years away.
40. IOU's and POU's must enter into Rule 21 contracts with ERR within reasonable time. Timelines shown in IREC documents seem reasonable.
41. ERR must come on-line with-in 3 years of Rule 21 contract with an IOU or POU. If there is not a reasonable extension, then the ERR is responsible for all costs incurred and will forfeit their contract. .
42. Term of Contract. Terms should allow changes to reflect the current requirements to meet AB 32. In other words, if 20% RPS is not meet by 2010, then retail rates and other incentives on exported power should be increased and all existing contracts changed to reflect these new rates and incentives.
43. IOU's and POU's need to fully embrace the value of RDG. For example, all rate payers are proposed to pay for the cost of the large, high voltage power lines required to transport the solar power from Imperial to San Diego. The large solar power projects would also get the benefits of all the solar programs. So therefore the true cost of the power is not being assessed to the solar power project. Yet RDG is not given credit for using the existing local power grid. RDG is actually helping mitigate the increase in local power use and demand. The IOU's and POU's are not incurring the costs to improve the local grid. This means that RDG should be looked at like peaker power plant power, get paid higher amounts and receive expedited permitting and lower fees.
44. ERR should locate as close to or within the areas of load. In the recommendation above, the solar can be located in San Diego (on roof tops, garages, parking lots, walkways, etc.). Only where the specific renewable energy source is located a great distance from the load should transmission lines be built. The cost of this interconnection should be paid for by the ERR, not the rate-payers so that the true cost of this renewable energy is included in the economic viability of the ERR project.
45. Customers who are increasing their service requirements, but are meeting or exceeding ½ this increase by using on-site renewable energy (becoming or expanding an ERR) should be charged only ½ of the cost for those service improvements. This would encourage existing customers to consider mitigating their new electrical load with renewable energy and becoming an ERR.
46. Competitive Renewable Energy Zones (CREZ) should be eliminated. Instead a policy whereby a balanced (equal) development of renewable energy with-in all load areas is superior. The generation needs to be close to the load, preferably on the same site. This reduces the need for added infrastructure and the costs, delay and impacts it causes.
47. Many of these suggestions have been practiced since 2004 in New Jersey's and Colorado's award winning statewide utility net-metering and RPS legislation. I would suggest that it might be simple to look at and adopt them as a unit; that we not reinvent the system.

SPECIFIC RECOMMENDATIONS FOR AB 1969/FIT

1. All changes should be enacted immediately. This would help meet all outcomes.
2. All renewable fuels, as defined in PRC 25741 and PUC 399.11 Decision 03-06-071 should be included.
3. AB 1969 provisions should have a moving window of application for at least five years. This would automatically extend the program annually, for the next five years, and allow seamless expansion of RPS development. This is necessary for businesses, government, IOU's and POU's to do long term planning, expansions, improvements and R&D.
4. Make all target goals of AB 32, RPS and AB 1969 minimums. Consider penalties if they are not met by the IOU's and POU's.
5. Continue target goals of AB 32, RPS and AB 1969 beyond 2020. They need to be more aggressive and definitive, ie. 20% by 2010, 30% by 2015, 40% by 2020, 50% by 2025, 60% by 2030, 70 % by 2035 and 80% by 2040.
6. Move upper energy production limits covered by AB 1969/Feed-In Tariff (FIT) to 20 MW.
7. Remove the RPS cap for the state, IOU's, POU's and others. If these entities want to or the economy warrants going beyond the cap, they should be able to. ERR's need to know that they will not be cut-off from interconnection as we approach these caps.
8. "Must Take" provisions should stay in place for RPS and should apply to all IOU's, POU's and others.
9. Provide a clear, simple up-front picture of costs and what needs to be done to complete the application and interconnection. Samples of these are shown on the IREC website. Few businesses, even IOU's, would go into any project without these being determined prior to commencement. Usually, estimates are prepared as part of business and are free. This is not the case in AB 1969 as currently written.
10. There are no clear cut or consistent requirements of what is required to interconnect. These requirements can be specified by using generation output brackets. These requirements should be the same for all IOU's and POU's, so that ERR's have consistent costs and requirements, no matter where they are located. The standard could be the Institute of Electric and Electronics Engineers (IEEE) Standard # 1547, UL 1741 or the IREC (2007) "Interconnection Standards for Distributed Generation Model".
11. External disconnect switches should not be required on systems less than 1.5MW.
12. Interconnection requirements should not be unreasonable, difficult or expensive. For example, ERR's should not be required to feed all generated power back to the main, but should be able to use the same subpanels and wires used for the connected load. This would save rewiring costs, material costs and resources.
13. The rules should be available to all ERR's so that they would not need to hire electrical engineers or consultants for each small project.
14. There needs to be means by which an ERR can object to excessive requirements. Excessive requirements will inhibit meeting the goals and RPG projects.
15. Establishment of an Information Clearinghouse, ERR Ombudsman and advocacy group is critical. This should cover all aspects of these projects and would include, but not be limited to; soil, water and air emission regulations, land-use regulations, fire and safety regulations, utility interconnections and available support funders.
16. All fees and interconnection costs should be revised. These are way out of line with the scope of small projects. They are truly game stoppers, as no business that is doing this is going to be able to recoup these costs, especially at the current Market Price Referent (MPR). Renewable Rule 21 installations are exempt from all or most of these costs on generation facilities up to 1.5 MW. The same should be true for AB 1969. Fees and costs shown in IREC documents seem reasonable.
17. Customers who are increasing their service requirements, but are meeting or exceeding ½ this increase by using on-site renewable energy (becoming or expanding an ERR) should be charged only ½ of the cost for those service improvements. This would encourage existing customers to consider mitigating their new electrical load with renewable energy and becoming an ERR.

18. If the proposed Renewable Distributed Generation (RDG) maximum output capacity from a ERR does not exceed the existing service capacity, then the fees, interconnection and meter costs should be minimal (less than $500) or none.
19. Increasing generation capacities of existing ERRs should be encouraged. This can be for the same or a different type of renewable power. Application and interconnection fees for these expansions should be ½ of the application fees for a new ERR or $500, whichever is lower. The logic behind this is that these ERRs already know the rules and requirements, the IOU's and POU's already are doing business with these ERRs and the likely follow-through and completion of this additional generation capacity is high.
20. Remove the Federal Energy Regulatory Commission (FERC) fees on ERR's of capacity less than 20 MW. I understand that SCE does not have this requirement, but PGE does. Why?
21. No departed load or stand-by charges. These are currently not charged under Rule 21. Since most ERRs are actually generating for a greater percentage of the time than solar, why should these charges be placed on them? Additionally, customers who use less electricity due to efficiency improvements, some of which are paid for by the IOU's, do not pay these charges.
22. Consider using the TOD retail cost of electrical energy for payment and cost of power instead of MPR.
23. Or establish a Renewable MPR (RMPR) schedule. RMPR rates should be at least TOD retail rates x 90%.
24. RMPR should have different payments for different renewable technologies. Encouraging diverse sources of energy is good and necessary to meet the RPS. However, some of these require higher levels of support. These RMPR's can be adjusted, from time to time, to encourage development of emergent technologies. For example, if there is a major breakthrough in PV solar efficiencies, then continue with the current RMPR–PV Solar for a while to encourage development, conversion and usage of the new panels. Then at some time, when the adoption is "mature", this rate could be reduced without affecting other RMPR schedules.
25. Different RMPR's should reflect environmental impacts such as Fuel Life Cycle, Renewable Fuels, Green House Gas (GHG) reductions and Sustainable Fuels.
26. Create a Tier Schedule for RMPR. This would include the values above. Combination of fuels from the various Tiers should be allowed and benefits pro-rated. The following is a possible format;
    1. Tier 1- composed of renewable generation fueled by renewable, sustainably produced by-products of existing industries and low GHG emissions, such as;
        1. Non-edible, food by-products such as shell, hulls, pits, chaff, plant & animal waste bio-gas, waste animal and vegetable by-products, fish by-products and waste, waste organic material, etc.
        2. Manufacturing by-products and waste such as heat, paper, wood chips, scraps and sawdust, fabric scraps, etc.
        3. Sewage treatment and waste disposal site bio-gas
        4. Solar and wind produced by DG's on roofs, parking covers, shade structures, walkways, etc. within load centers
        5. Energy can be produced by anaerobic or aerobic digestion; pyrolysis, plasma, thermo combustion, bio-diesel, oil combustion, etc.
        6. Electricity can be produced by fuel cell, Internal Combustion Engines (ICE)(Spark or compression ignited), turbine, etc.
    2. Tier 2 - composed of renewable generation fueled by renewable, non-food products, such as;
        1. Using resources not suitable for food or fiber production such as fuel from toxic land mitigation, marginal land (ie. Westland's tree project), algae production tanks with recycled resources, etc.
        2. Fuel produced without the use of irrigation, fertilizers, etc.
        3. By-products of agricultural and forestry production that need to be gathered from field to use, such as corn Stover, straw, hay, pruning products, forestry slash, etc.
        4. Solar and wind produced on "farms" that are near load centers
    3. Tier 3 – fuel produced from resources that can be used for food, fiber, environment or building materials
        1. Grain ethanol, methanol

2. Grain, soy or palm based oil or bio-diesel
3. Solar and wind produced on “farms” that are far from load centers
4. Algae farms that use resources not recycled from other sources

27. Tiered RMPR rates would be higher for those that provide the highest environmental and energy benefit.
28. The RMPR should be substantially increased if the IOU’s and POU’s do not meet RPS, AB 32 and AB 1969 goals, thus stimulating compliance.
29. RMPR for emergent technologies should be set and kept reasonably high to reward innovators, first and early adopters. They can subsequently be reduced as technology “matures”.
30. ERR’s should not pay non-energy charges for power used on-site.
31. IOU’s and POU’s can only count inter-connected and operating ERRs toward meeting the goals of RPS, AB 32 and AB 1969. No credit should be given for those ERRs that are not producing.
32. Remove the current restriction of Solar Initiative funded or tax incentivized arrays, incentive programs and SGIF from participating in the FIT program.
33. Clarify that ERRs that have received grants, funds or other incentives from various government and non-government programs are eligible to participate in the AB 1969/FIT program. The idea is that those programs would only incentivize desired, new, emergent, speculative or R&D technologies or other needs such as GHG, energy and emissions reduction.
34. Accommodate the usage of different types of renewable generation on the same electrical service. Would possibly need to pro-rate RMPR based on the annual output of each type of renewable generator.
35. Federal tax credits (currently $.01/kWh Federal, only on power sold to a qualified IOU) (State too?) should be based on all renewable generation production, even that which is not interconnected and/or used on site of ERR.
36. Additional credit should be given for on-site use at a greater level than RMPR as it lessens impacts and costs to the grid and other customers. It makes more electricity available without building more generators just as energy conservation does.
37. Tax credits for renewable energy generation should stay with the ERR.
38. All Green Attributes (including but not limited to; carbon and GHG credits) or expenses should stay with the ERR.
39. Renewable Energy Credits (REC) belong to the ERR.
40. IOU’s and POU’s can count energy produced by ERR, including electricity used on-site, towards meeting RPS, AB 32 and AB 1969 goals.
41. All meters should be TOD. This would encourage generators to maximize production and minimize use during TOD Peak Rates (times when CA needs power). This would reduce the need for peaker-plants and the high costs and emissions associated with them. The ability of ERR’s to produce power during these times is a benefit to all rate payers. The IOU’s and POU’s charge more for electricity used during these periods. ERR’s should be rewarded for this.
42. TOD Net-Metering should be used on all renewable generation, at least up to 2MW systems. It is currently not clear as to how the metering and billing is handled under AB 1969 with bi-directional meters. Again, this is potentially a game stopper. If we are selling all the power generated at MPR, buying all the power used at retail, ERR’s would be losing lots of money. The best method would be a net meter arrangement, paying retail for net purchases or getting paid RMPR for net exports. All non-electric costs should be paid only on the purchased power further stimulating renewable energy production.
43. TOD Net-metering should be available to all classes of ERR.
44. If TOD bi-directional meters are required, then the ERR should only be billed or paid for the net power used or produced. It should not be “dual metering” or “net billing”. All non-electric costs should be paid only on the net purchased power.
45. ERR’s should be required to report to the IOU’s and POU’s total renewable energy production. This can be done annually, semi-annually or quarterly. This report would be used to determine progress towards the goals and for renewable production tax incentive purposes. These meters can be separate meters or on the generator panel to show net production. Parasitic loads from the generator should not be included in these numbers.
46. All ERR meters should be able to be remotely monitored and read wirelessly.

47. True-Up Periods need to be tailored to the type of renewable generation and service. I would suggest some sort of compromise "true-up period" if different renewable technologies are on the same meter. For example, we need an annual true-up. Our solar output varies over the course of the year. Our biomass producer gas is used to off-set propane use during harvest (October) and it is not available to produce electricity during this month. This is also our month of highest electrical usage. It would be best for us to be able to amass electrical credits to use during this time. Thus, we would be encouraged to produce excess electricity during the summer months when CA needs it the most and use it during harvest when we need it the most and CA does not. This would also simplify and reduce billing and payments for the IOU's, POU's and the ERR. There are annual pay-out programs that allow an ERR to use net-metering over the course of the year and then pay for the power used or to be paid for the excess power produced. CA should transition to this type of program.
48. RMPR TOD production rates should be higher than normal RMPR TOD purchase rates. This would be similar to Peaker Plant Rates and would encourage those ERRs that can produce exportable power during these peak periods to do so.
49. "Wheeling" of excess electricity production between service accounts on a customer's consolidated bill should be allowed. This allows ERRs to efficiently produce power where the fuel is and use electricity where the load is, usually within a short distance. This is allowed with dairy bio-gas..
50. RMPR rates should not be based on natural gas MPR rates. Natural gas rates are subsidized and so therefore are artificially low. They are also unstable. The reason why RPS has not been met in the past is because natural gas prices fell, driving down the MPR rates. This made RPG uneconomical. Increasing RPS and the number and types of ERRs will add stability to energy costs, actually benefitting rate-payers.
51. RMPR rates need to be set high at this point to encourage rapid ERR development in order to meet the AB 32 goals of 2010. This deadline is less than 2 years away.
52. IOU's and POU's must enter into AB 1969 contracts with ERRs within reasonable time. Timelines shown in IREC documents seem reasonable.
53. ERRs must come on-line with-in 3 years of AB 1969 contract with an IOU or POU. If there is not a reasonable extension, then the ERR is responsible for all costs incurred and will forfeit their contract.
54. ERR needs to have 7 year RMPR rates, adjusted for inflation, from time of AB 1969 contract with IOU or POU to guarantee income to ERR. This is necessary to insure stable investment interest in ERRs.
55. Term of Contract. Terms should allow changes to reflect the current requirements to meet AB 32. In other words, if 20% RPS is not meet by 2010, then RMPR and other incentives should be increased and all existing FIT contracts changed to reflect these new RMPR's and incentives.
56. IOU's and POU's need to fully embrace the value of RDG. For example, all rate payers are proposed to pay for the cost of the large, high voltage power lines required to transport the solar power from Imperial to San Diego. The large solar power projects would also get the benefits of all the solar programs. So therefore the true cost of the power is not being assessed to the solar power project. Yet RDG is not given credit for using the existing local power grid and interconnection. RDG is actually helping mitigate the increase in local power use and demand. The IOU's and POU's are not incurring the costs to improve the local grid. This means that RDG should be looked at like peaker power plant power, get paid higher amounts and receive expedited permitting and lower fees.
57. ERR should locate as close to or within the areas of load. In the recommendation above, the solar can be located in San Diego (on roof tops, garages, parking lots, walkways, etc.). Only where the specific renewable energy source is located a great distance from the load should transmission lines be built. The cost of this interconnection should be paid for by the ERR, not the rate-payers so that the true cost of this renewable energy is included in the economic viability of the ERR.
58. Customers who are increasing their service requirements, but are meeting or exceeding this increase by using on-site renewable energy (by becoming or expanding an ERR) should not be charged for those service improvements. This would encourage existing customers to consider mitigating their new electrical load with renewable energy and becoming an ERR.
59. Competitive Renewable Energy Zones (CREZ) should be eliminated. Instead a policy whereby a balanced (equal) development of renewable energy with-in all load areas is superior. The generation needs to be close to the load, preferably on the same site. This reduces the need for added infrastructure and the costs, delay and impacts it causes.

60. Many of these suggestions have been practiced since 2004 in New Jersey's and Colorado's award winning statewide utility net-metering and RPS legislation. I would suggest that it might be simple to look at and adopt them as a unit; that we not reinvent the system.

Specific needs for Dixon Ridge Farms

1. We have had an 16kW solar array interconnected through a net-meter since Dec. 2004. We added a 50kW generator fueled by gasified walnut shells (a by-product of our walnut processing) in Nov. 2007. We assumed that since we were already a Rule 21 Net Meter EER and had interconnection, it would be very easy to add this. I couldn't have been further wrong.
2. We have been trying to get this done since Nov. 2007. We have tried to get straight answers from PGE and are still getting different ones with every meeting. With the help of Senator Wolk's staff, we have explained our problem to various well connected individuals, including Chairwoman Mary Nichols, Secretary AG Kawamura, Secretary Chrisman, various people in the CEC, CARB CDFA, CPUC, etc.
3. We have submitted a Rule 21 Multi-tariff Non-export application, due to the mix of solar and biomass. This was the suggested route by PGE in May 2008. We have "played the game". We paid PGE for the analysis, hired an engineer and have had more and more requirements placed on this application. The most onerous of these requirements is to not export power and to pay for all the equipment that would need to be purchased and installed to meet this requirement. This equipment would cost at least $50,000. It would require the generator to throttle back, reducing power output and efficiency.

   We asked PGE about AB 1969, but were told it was not applicable for our project. The stated reason was because the solar was installed with Solar Initiative tax credits and The BioMax was funded by a CEC grant. AB 1969/FIT states that we cannot benefit by "double dipping". We recently found out (from PGE) that it may now be OK to apply under AB 1969.

   Some aspects (such as allowing exportation of excess power and being paid for this power) are better under AB 1969. Some aspects, such as not being allowed to use a net-meter with an annual true-up are not. The biggest issues with AB 1969 are the various fees that PGE requires to be paid. They amount to about $50,000. They also will not reimburse or reapply the Rule 21 interconnection fees we have already paid. We have been told we would have to pay for departed load and demand charges.

   Speaking for myself (but I think CPC would echo this) I don't want to pay again. We were following their lead. We should get some sort of "credit" for what has already been done. Additionally, the AB 1969 fees are outrageous in light of the fact that we will only produce about $40,000 worth of electricity per year, none of which will be exported on an annual basis. There has been no real means for negotiation.

4. The term of contract is not clear. PGE stated that we could alter and/or terminate the contract in the future when changes and/or adjustments in the AB 1969, RPS and MPR happen. AB 1969 seems to state the opposite. Contacts within the PUC believe that changes will be applied retroactively. What is the answer?

5. We have suggested making our interconnection a "pilot project". This can happen by using some of the improvements to Rule 21 or AB 1969 listed above. One option would be to finish our application under Rule 21, and be similar to a dairy biogas agreement. This would allow us to use the existing annual true-up period, allow the possibility to export power for a credit and to wheel excess power to another account (as the dairy bio-gas customers do) on our consolidated bill. PGE has not responded to this suggestion.

6. Another option would be to have the paid interconnection fees applied to an AB 1969 application and to wave or reduce the remaining fees and charges. We may have to forfeit the benefits of our Rule 21 solar system. We would prefer to keep our Net Meter (actually change it to a TOD-Net Meter) as opposed to a bidirectional meter. A bidirectional meter would require us to install separate wires from the BioMax to the existing service panel. This would be costly, difficult to do and would use more resources. We could then have a monthly, quarterly or annual payment cycle at MPR and retail for exportation or importation respectively.

7. We have a CEC grant requirement to be interconnected. We cannot be interconnected under the existing rules. We need to get this resolved so that we can move on.

8. It appears that AB 1969 prohibits us from participating in the AB1969/FIT because of the solar initiative credits and the CEC grant for the BioMax unit. This needs to be addressed.

9. We need to be able to maximize our BioMax electrical output so that our GHG emission per kW is the least possible. We cannot do so until we get interconnection with full exportation capabilities.

10. We want to continue on our path towards greater renewable generation and for on-site improvements. We cannot do so until we get interconnection.

11. We want to reorganize our on-site power distribution, to better serve the renewable generation and increase our processing plant loads. We cannot do so until we get a better picture of what we need to do to interconnect and under what conditions.

12. We have been attempting to get interconnection with PGE since November 2007. We have all the safety protocols in place. We have a net-meter already in place. We can be safely interconnected with PGE with no additional cost to PGE or to us. We can be interconnected in a matter of hours. There is absolutely no (reasonable) reason why this should not happen.

PGE has a poor reputation in this area. The more we have worked in this field the greater number of horror stories we hear. Much time and many resources have been used to inhibit DG, RDG and small ERR. Much time and many resources have been used to promote PGE's “green business practices”. There is a big disconnect between the two. This is why I have proposed this be termed a “pilot project” to allow a new model to be promoted. I think it would be much more productive to spend our time working on what can be, instead of the problems of what we have. There clearly are many problems with the rules as they now exist. We will be happy to work on these changes.

Secretary Kawamura, Secretary Chrisman, Senator Wolk, Susan Brown with CEC and others have asked how things are going. I have had to honestly say that they have not progressed. They have asked what they can do to help move it forward. If PGE cannot move beyond what we have due to their rules and regulations, then we have to move to the next step of involving them to change the rules and regulations. This kind of project is what the Governor, the Legislature, President Obama and the nation wants. It will happen. It merely is a question of how, when and at what cost.

I appreciate your help in trying to move this forward. We have been working with PGE on this issue for over a year. We need to get beyond understanding what we have that doesn't work, to what we need to do to make it work. Hopefully this is what we can talk about and get implemented.