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## **Cogeneration and Small Power Production: Florida's Approach to Decentralized Generation**

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# Cogeneration and Small Power Production: Florida's Approach to Decentralized Generation

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## **Abstract**

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**KEYWORDS:** Cogeneration, Decentralized Generation, Florida

# Cogeneration and Small Power Production: Florida's Approach to Decentralized Generation

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## I. Introduction

The changing economics of electricity generation in the 1970's, coupled with the 1973-74 oil crisis, prompted both a legislative and societal examination of the United States' approach to decentralized electricity production.<sup>1</sup> During the early 1970's, costs associated with the expansion, maintenance and replacement of generating capacity increased sharply due to inflationary pressures while the growth rate of electricity demand fell.<sup>2</sup> The oil embargo sent fuel costs skyrocketing and further devastated the electric power industry,<sup>3</sup> as cheap fossil fuel had molded the development and operating structure of the industry.<sup>4</sup> Accordingly, every administration and Congress since 1973 has supported energy conservation to reduce capacity expansion needs and has encouraged energy supply expansion to reduce foreign oil dependence.

President Carter responded to this energy crisis by proposing a national energy plan. On November 8, 1979 President Carter signed the National Energy Act (the Act). Three parts of the Act, the Public Utility Regulatory Policies Act (PURPA), the National Gas Policy Act, and the Energy Tax Act of 1978, contain provisions relating to cogeneration and small power production.<sup>5</sup>

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1. Lock, *Encouraging Decentralized Generation of Electricity: Implementation of the New Statutory Scheme*, 2 SOLAR L. REP. 705-752, 707 (1980).

2. *Id.* Cost increases resulted from increased capital costs necessary to finance plant construction. Additionally, consumption per dollar GNP fell substantially from 1970 to 1971. See 1983 UNITED STATES STATISTICAL ABSTRACT exhibit No. 973.

3. For example, the percent price change increase measured in 1972 constant dollars of crude oil and bituminous coal for the period 1973-75 was 65.8 percent and 96.4 percent respectively. *Id.* exhibit No. 974.

4. Lock, *supra* note 1, at 707.

5. See, e.g., 15 U.S.C. ch. 60 (Supp. 1983); 16 U.S.C. ch. 46 (Supp. 1983).

This legislative encouragement of decentralized electricity production is planned to yield several major societal benefits in the long run: an increased efficient utilization of energy resources with a commensurate saving of scarce oil and gas reserves,<sup>6</sup> an enhanced use and development of renewable energy resources,<sup>7</sup> a greater flexibility and precision in planning utility capacity because of the smaller generating units utilized in the decentralized structure<sup>8</sup> and a decrease in business and financial risks associated with satisfying fluctuating or uncertain future demands on utility systems due to the faster construction times for smaller units.<sup>9</sup> The realization of these benefits, however, depends on the strength of the federal incentives provided in the Act and their effective implementation by the appropriate federal and state agencies.<sup>10</sup>

Congress substantially delegated the practical implementation of PURPA's provisions to the individual states' public commissions (PUCS),<sup>11</sup> as PURPA establishes only broad guidelines necessary to convey legislative intent.<sup>12</sup> PURPA requires these commissions to promulgate rules pursuant to the Federal Energy Commission's (FERC) regulations.<sup>13</sup> Under FERC's regulations, the states must establish rates for utilities' purchases and alternatively establish rates for utili-

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6. California Public Utilities Commission (CPUC) Order No. 91109, OII No. 26 (December 19, 1979) at 13-14. Cogeneration offers efficiencies by permitting the utilization of fuels in a more efficient manner when combined by cogeneration that is possible under conventional technologies. *Id.*

7. Certain energy resources are renewable such as wind and solar power.

8. California PUC Decision No. 91109, *supra* note 6. The lead time required for the construction of a cogeneration facility is estimated to be several years less than the time required for the construction of a large central station power plant. Thus, customer demand need not be projected so far into the future making demand forecasts more accurate. *Id.*

9. *Id.* Benefits to ratepayers could result because non utility owned cogenerators have to raise the required capital for construction of the cogeneration facility and these financing costs would not to be borne by the ratepayers. Further, the cogenerator's facility is not included in the utility's rate base and the cogenerator is only reimbursed for actual production, thus, the ratepayer does not have to bear the costs of any unscheduled outages of that facility.

10. *See generally*, 16 U.S.C. § 824a-3 (Supp. 1983) (discussion of federal incentives for decentralized power generation).

11. 16 U.S.C. § 824a-3 (f)(1) (Supp. 1983). The provision, in part provides: "after any rule is prescribed by the Commission . . . each state regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for any electric utility for which it has ratemaking authority." *Id.*

12. *See, e.g.*, 16 U.S.C. § 824a-3 (a) (Supp. 1983).

13. 16 U.S.C. § 824a-3 (f) (Supp. 1983).

ties' sales to these co-producers in a manner to effectuate and provide incentive for the development of decentralized electricity generation.<sup>14</sup> However, the establishment and implementation of these rates to encourage this development of decentralized electricity generation has remained the most controversial provision of PURPA.

This article will examine Florida's recent unique implementation of decentralized power production within the scheme of PURPA. As background, the institutional barriers that long prevented the development of decentralized power production will be discussed. The scheme and purpose of PURPA will then be identified with a corresponding focus on appropriate FERC regulations. With this background, the final section will examine state implementation of the regulations and their potential implications with particular emphasis on Florida.

## II. Institutional Barriers to Decentralized Electricity Production

Electricity, as an energy form, cannot be stored and, therefore, must be consumed or lost. This physical property is significant for two reasons. First, the proper distribution of electricity to potential users requires an efficient transmission system. Second, the inability to store electricity demands a sufficient generating capacity to satisfy user needs during those times of the day and year when electrical consumption peaks. Accordingly, the construction of transmission systems and productive capacity should necessarily extend beyond current demand. The necessity of this construction results in extensive plant, property and equipment investments carrying large fixed costs. Because electricity production is so capital intensive, economies of scale dominate a electric utility because costs decrease as sales increase. As production and corresponding sales increase, large fixed costs are distributed over a greater number of units (i.e., kilowatts) thus decreasing the fixed costs per unit.<sup>15</sup> This economic behavior is shown in Exhibit 1:

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14. 18 C.F.R. § 292.401 (a) (1983). This section provides in part: "each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C." *Id.*

15. L. WEISS & A. STRICKLAND, REGULATION: A CASE APPROACH 3-5 (1976).

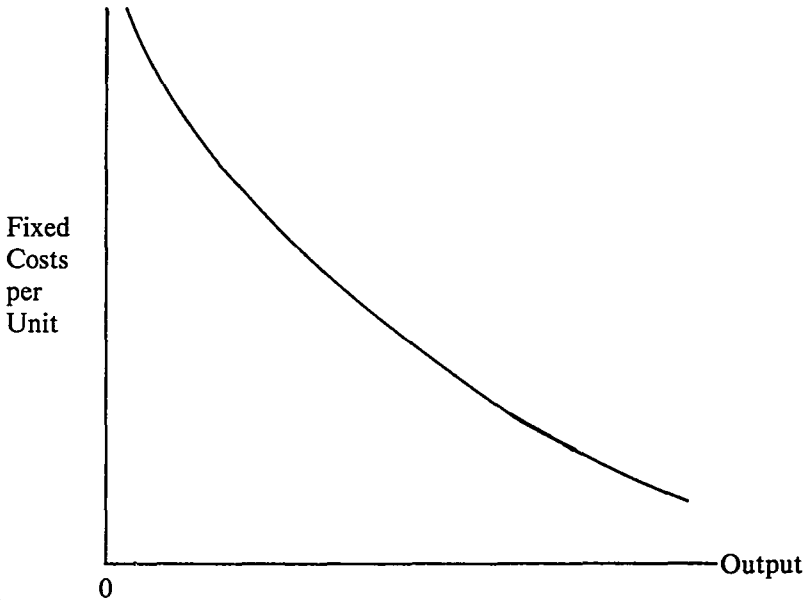


EXHIBIT 1

These economies of scale and improving technologies allow the utility industry to reduce per unit costs by increasing capacity and encouraging customer sales.

Because of these scale economies, electricity during the early 1900's quickly proved to be a relatively safe, cheap and attractive power source, and its use spread to numerous industrial, commercial and residential application. As utilities continued growing, the utilities' ability to provide electricity at steadily declining rates made decentralized generation uneconomical. State and local governments began regulating production facilities as public utilities, and years of large-scale concentrated generation engendered regulatory structures which created economic and insitutional barriers to decentralized electricity production. The states granted monopolies over electricity generation and distribution to these existing public utlilties based on the theory that electric power production was a natural monopoly. A natural monopoly exists when the lowest cost per unit results when only one company exists in a decreasing cost industry as demonstrated in Exhibit 1. The one enterprise's fixed costs can be spread across more sales than if two firms must split the market demand. Thus, the idea of a government imposed monopoly on power production and distribution was well founded and in the ratepayers' best interest.

The distribution of power remains a natural monopoly because competition between electric utilities would require duplicate transmission and distribution systems which have sharply decreasing costs.<sup>16</sup> Because of changing economies and technologies, however, the generation of power is no longer a decreasing cost proposition.<sup>17</sup> Indeed, in electric generation some competition would be feasible if all generating companies could bid for the distribution systems.<sup>18</sup> Notwithstanding this economic fact, the utilities' control over the distribution systems has perpetuated their monopoly over production even though smaller facilities could generate at lower costs. Generation cost efficiencies are irrelevant if the electric power can not be delivered.

The public utilities' transmission and distribution control substantially rendered small producers' sales to parties other than the utility itself virtually impossible. Because of their monopoly position, public utilities lacked incentives to purchase electric power or, further, to purchase the electricity at an appropriate market rate. In addition to the suppressed purchase price, uncertainty existed as to the treatment of these small producers as public utilities and as subject to the same regulation, public scrutiny, controlled profits and administrative burden as a public utility. Finally, public utilities could also charge discriminatory rates to smaller producers for such services as back-up and maintenance power to discourage their operation.<sup>19</sup> Thus, the lack of an open market for electricity sales, coupled with the administrative uncertainty of being regulated as a public utility, discouraged potential decentralized generation. This inflexible situation existed when the oil embargo occurred. These barriers, however, prevented a receptive response which highlighted the need for a reorganization of electricity generation.

### III. Federal Legislative Response—PURPA

Sections 201 and 210 of PURPA contain the primary legislative response to these institutional and economic barriers to decentralized generation.<sup>20</sup> PURPA establishes broad guidelines<sup>21</sup> and requires the

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16. See L. WEISS, *supra* note 15, at 4-5. The logistics of having multiple power lines throughout the service area by competing power products would be cost prohibitive and aesthetically distasteful.

17. Lock, *supra* note 1, at 713-14.

18. See L. WEISS, *supra* note 15, at 5.

19. 45 Fed. Reg. 17,959 (1980).

20. See 16 U.S.C. § 824a-3 (Supp. 1983).

FERC to issue explicit rules for the encouragement of cogeneration and small power production which state public utility commissions must implement.<sup>22</sup> Although the FERC regulations permit state discretion, three requirements are clearly set forth by the provisions' language.

First, a public utility is required to purchase all power offered by the facility at the utility's full "avoided cost". Thus, qualifying decentralized facilities are conceptually guaranteed a market at an economically fair price.<sup>23</sup> Avoided cost represents the cost the utility would have incurred from either generating or purchasing from another supplier, to have that additional increment of power.<sup>24</sup> Second, interconnection with a utility system's electric grid, which guarantees qualifying facilities a limited distribution and transmission system,<sup>25</sup> is required. This interconnection provision is implicit and critical to the effective right to sell the electricity because public utilities' monopolies on distribution systems are overridden. Thus, qualifying facilities can effectively shop for a competitive price. Finally, if the qualified facility chooses,<sup>26</sup> it must be permitted to purchase electricity from the utility at non-discriminatory rates. This purchase option enables small cogenerating facilities to have sufficient backup power for their own operation if their own systems fail. The successful implementation of these requirements determine the effectiveness of the Congressional incentive to encourage cogeneration and small power production.

To obtain these federal and corresponding state guarantees, a facility must qualify under the FERC provisions and under the respective state regulations.<sup>27</sup> The federal regulations distinguish between

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21. 16 U.S.C. § 824a-3 (a) & (b) (Supp. 1983).

22. 16 U.S.C. § 824a-3 (a) (Supp. 1983).

23. Lock, *supra* note 1, at 713. Each public utility is required to purchase energy and capacity power from each qualifying facility at the public utility's avoided cost. 18 C.F.R. § 292.303 and 292.304 (1983).

24. 18 C.F.R. § 292.101 (b)(6) (1983). This provision defines avoided cost as the "increased costs to an electric utility of electric energy or capacity or both which, but for the purposes from the qualifying facilities, such utility would generate itself or purchase from another source." *Id.*

25. 18 C.F.R. § 292.303 (c) (1983). This section requires electric utilities to make interconnections with qualifying facilities as is necessary to accomplish purchases or sales as required by the subpart. *Id.*

26. 18 C.F.R. § 292.305 (b)(1) (1983). This provision requires public utilities to furnish qualifying utilities with (i) supplementary power, (ii) back-up power, (iii) maintenance power and (iv) interruptible power upon request. *Id.*

27. See 18 C.F.R. § 203 (1983); FLA. ADMIN. CODE 25-17.80 (1983). There are



cogenerators and small power producers, although both facilities are regulated virtually identically. The FERC regulations define a cogenerator as a facility which produces electric energy in addition to some form of useful energy utilized for industrial, commercial, heating or cooling purposes.<sup>28</sup> Aside from certain efficiency standards specified in the regulations<sup>29</sup>, the productive capacity of the facilities is not limited. However, a facility does not qualify as a cogenerator if an electric utility owns more than fifty percent of the equity interest in the plant.<sup>30</sup> Alternatively, the regulations define a small power producer as an electric generating facility utilizing as its primary energy source biomass, waste, renewable resources, geothermal resources or any combination thereof. The fifty percent ownership restriction is also imposed on small power producers.<sup>31</sup>

Beyond these qualification criteria, the regulations delegate broad authority to the states to implement rules in accordance with the intent of PURPA. The Florida Public Service Commission (FPSC) has adopted the FERC's qualifying criteria for cogenerators and small power producers, thus simplifying the qualifying process.<sup>32</sup>

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several benefits for qualifying as a cogenerator or small power producer in addition to those cited in the text. The most important is that such a qualifying facility will be exempt from federal and state public utility regulation. 18 C.F.R. § 292.601 and 292.602 (1983).

28. 18 C.F.R. § 292.202 (c) (1983).

29. 18 C.F.R. § 292.205 (a) and (b) (1983).

30. 18 C.F.R. § 292.206 (a) and (b). This section reads, in part:

[A] cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

*Id.*

31. 18 C.F.R. § 292.204 (1983).

32. FLA. ADMIN. CODE 25-17.80 (9-2-83). The Florida Public Service Commission adopted FERC's qualifying criteria as their own. The Florida Commission provided, however, that those facilities failing to satisfy the adopted FERC criteria may still petition the FPSC for qualifying status for the purpose of receiving payments under the rules. *Id.*

#### IV. State Implementation

State public utility commissions (PUCs) are required by section 210 of PURPA to implement the FERC regulations governing the purchase and sale of electric power by qualifying facilities. The rates established by the PUCs must act as a price signal to encourage the development of decentralized generation in accordance with the intent of the PURPA. The major areas of state discretion are set forth below:

##### A. Sales By Qualifying Facilities

Section 210 of the PURPA requires PUCs to establish rates for electricity sales by qualifying facilities (QFs) to public utilities.<sup>33</sup> PURPA provides that established sales rates "shall not exceed the incremental cost to the electric utility of providing that energy."<sup>34</sup> Clarifying PURPA's language, the FERC regulations further state that electric utilities will not be required to purchase power at rates exceeding the utility's avoided cost.<sup>35</sup> The regulations define avoided cost as the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source if the purchase from the qualifying facility has not occurred."<sup>36</sup> Although the regulations provide a number of criteria to consider in determining avoided costs,<sup>37</sup> the rules leave considerable

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33. 16 U.S.C. § 824a-3(f) (Supp. 1983). This section requires that one year following the issuance of FERC's rules, each state commission shall after notice and opportunity for public hearing implement rules pursuant to the mandate of PURPA. *Id.*

34. 16 U.S.C. § 824a-3(b) (Supp. 1983). This section also provides that the purchase rates shall be just and reasonable to customers of the electric utility, in the public interest, and not discriminate against qualifying facilities. *Id.*

35. 18 C.F.R. § 292.304 (a)(2) (1983).

36. 18 C.F.R. § 292.101 (b)(6) (1983).

37. 18 C.F.R. § 792.304 (3). These criteria include:

1. Availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
  - a) Ability of the utility to dispatch the qualifying facility;
  - b) Expected or demonstrated reliability of the qualifying facility;
  - c) Contract terms or other legally enforceable coliation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
  - d) Extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
  - e) Usefulness of energy and capacity supplied from a qualifying facility

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discretion to the PUCs concerning avoided costs calculations and QF purchase rate structure. Essentially, basing payments to QFs on avoided costs merely provides that payments will be calculated on a utility's marginal costs. Marginal costs represent the additional costs a utility incurs if a customer increases power usage at any given time. Thus, if the electricity a QF supplies to a utility permits that utility to avoid the costs of purchasing or producing that electricity, the QF receives as payment the utility's avoided cost. As shown in Exhibit 2, basing utility purchases on marginal costs rates is theoretically sound because utility purchases reflect the cost consequences to that utility of supplying that incremental electricity. The shaded area represents the marginal cost that a utility would incur in producing the additional  $x + 1$  unit of electricity. Thus, the utility pays the actual cost that would have been incurred if the utility had produced or purchased the energy from another public utility.

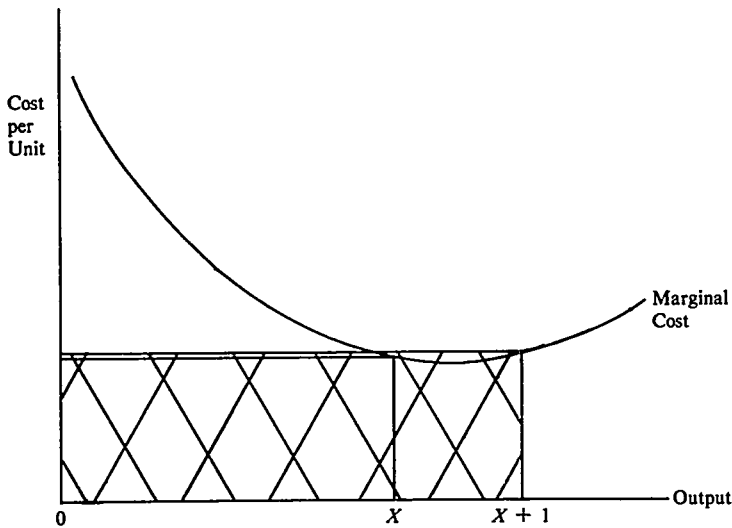


EXHIBIT 2

during system emergencies, including its ability to separate its load from its generation;

- f) Individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
  - g) Smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
2. Relationship of the availability of energy or capacity from the qualifying facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use.

*Id.*

FERC regulations subdivide avoided costs into energy cost and capacity costs.<sup>38</sup> Capacity costs represent the costs associated with the capability to deliver electricity and consist primarily of the facilities capital costs.<sup>39</sup> Generally, capacity costs can be thought of as the physical facilities necessary to generate electricity. Energy costs, alternatively, are the variable costs associated with the production of electric energy and represent fuel costs in addition to certain operating and maintenance expenses.<sup>40</sup> The Florida Public Service Commission's (FPSC) rules utilize the same distinction between capacity and energy costs in calculating avoided costs for firm as opposed to non-firm power.

## B. Non-Firm Power

Non-firm power or "as available" power, as termed by the FPSC, is energy produced and sold by a QF with no contractual commitment as to the quantity, time or reliability of delivery to the purchasing public utility.<sup>41</sup> The FPSC requires utilities to purchase as available energy from all QFs within their service area at the utilities' avoided energy cost.<sup>42</sup> Because as available energy lacks these crucial assurances, Florida's rules require only energy payments and do not provide for capacity payments.<sup>43</sup> The FPSC explicitly rejected the argument that FERC regulations require that all QFs delivering "as available energy" be compensated by a capacity payment.<sup>44</sup> The FPSC noted that FERC does not require that all QFs delivering "as available energy" receive capacity payments but, rather, only that such delivery *may* confer capacity related benefits which should then be compensated.<sup>45</sup> Further, the Commission interpreted FERC's regulations as establishing an if-then test: "if the evidence demonstrates that a QFs delivery of as-available energy confers capacity related benefits, then compensation for capacity credits should be made."<sup>46</sup> In the rule making proceeding, how-

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38. See *supra* note 36. This section draws the distinction between electric energy payments and electric capacity payments. *Id.*

39. 45 Fed. Reg. 12,216 (1980).

40. *Id.*

41. FLA. ADMIN. CODE § 25-17.825 (1) (1983).

42. *Id.*

43. *Id.*

44. Florida Public Utilities Commission (FPUC), Order No. 12634, Docket No. 820406-EU (Oct. 27, 1983), at 9.

45. *Id.*

46. *Id.*

ever, the FPSC found that persuasive evidence did not exist in the record to justify such capacity payments.<sup>47</sup>

This approach reflects a realistic approach to capacity payments. The rationale underlying capacity payments can be simply stated. As the utility's service demands expand, guaranteed power is crucial to the satisfaction of customer needs. If QF production can defer the construction of a generating station by a public utility, then the QF has replaced the necessity of building additional capacity. Consequently, the QF should receive payments for this deferred capacity. If, however, power deliveries fluctuate between periods, then utilities can not depend on these deliveries during peak periods and need to construct the necessary capacity. Public utilities must expand capacity to meet these demands which the QFs fluctuating delivery could not satisfy with sufficient certainty. In this situation, no capacity needs have been avoided, thus rendering capacity payments improper.

Many PUCs, including Florida's, apply the concept of time-of-use rates to the purchase of "as available power." Under this methodology, rates reflect the value of QF generation to the utility system at different times.<sup>48</sup> The demand for power varies both with the time of day and the season of the year as shown in Exhibit 3:

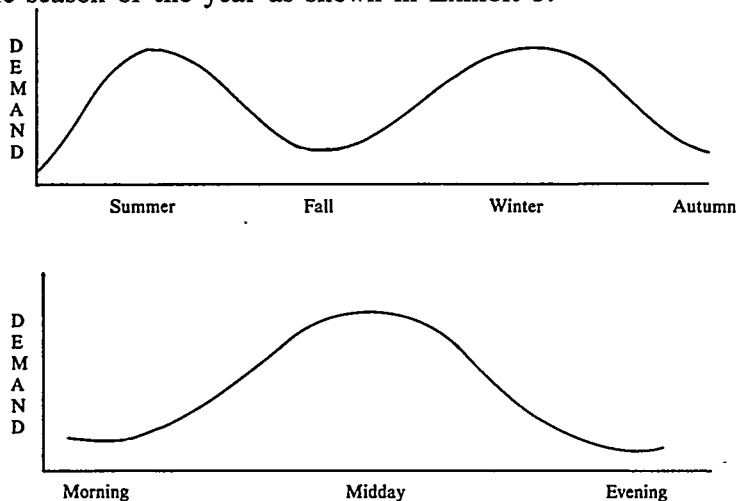


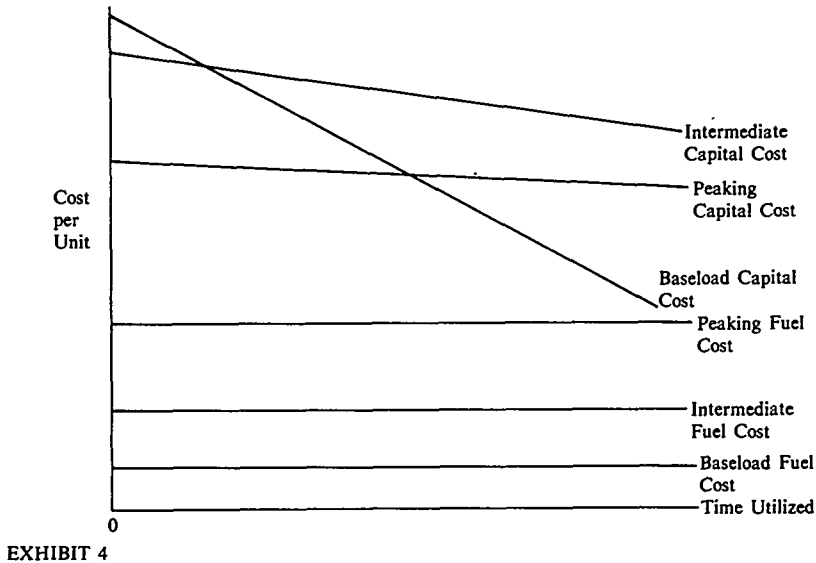
EXHIBIT 3

47. *Id.* The FPSC found that record indicated that Florida utilities included QF capacity in their expansion plans but this was an inadequate showing of what amount of this power would be sold on a firm basis. Thus, capacity payments were not supported by the record. *Id.*

48. Lock & Kuiken, *Cogeneration and Small Power Production: State Implementation Of Section 210 Of PURPA*, 3 SOLAR L. REP. at 673 (1981).

Utility generating equipment can be divided into three categories: baseload, intermediate, and peaking. Baseload equipment supplies that portion of the load which remains constant, regardless of the time or season. Baseload generating units are large and substantial warm up periods. Naturally, peaking units are small and have the ability to be placed on line quickly to satisfy sharp demand peaks. Intermediate generating units can be placed on line more quickly than baseload units and may be utilized a significant portion of the time as a spinning reserve. Generally, baseload generating capacity requires the highest capital costs followed respectively by intermediate and peaking units. Because peaking and intermediate units are utilized only a portion of the time, the actual capacity recovered from the ratepayers is often in the reverse order. Thus, when the capital cost is weighted by the time that the capacity is utilized, peaking units are the most expensive.<sup>49</sup>

In addition to capacity costs, fuel costs are generally higher when intermediate and peaking equipment are usually less efficient than baseload equipment. Also, baseload units usually consume less expensive fuels than intermediate and peaking units. Thus, QFs will receive the highest purchase rates for delivering power during peak demand periods when their power can reduce the utility's need to run the more costly units.<sup>50</sup> The relationship between these costs is demonstrated in Exhibit 4:



49. Eisenstadt, *PURPA and PV Systems*, 2 SOLAR L. REP. 1061-82 (1981).

50. *Id.*

In Florida, if the utilities do not negotiate a contractual rate with a QF in their service area, they must purchase "as available energy" at rates established in their standard contract tariff.<sup>51</sup> The standard tariff rates will be predetermined by the FPSC. Additionally, these tariff rates will be based on either the utility's actual hourly incremental costs for hours during which no economy energy transactions occur, the actual incremental costs after economy energy purchases, or the actual incremental costs before economy energy sales. Thus, Florida's tariff rates reflect time of day usage.<sup>52</sup> Alternatively, a utility may negotiate a separate contract rate with any QF either inside or outside its service area. In any case, as stated above, a utility is not required to pay for capacity costs.<sup>53</sup>

### C. Firm Power

The FPSC defines firm power as energy and capacity produced and sold by a QF pursuant to a contract and subject to quantity, time, and reliability of delivery contractual provisions.<sup>54</sup> The FPSC has taken a unique approach in calculating firm power payments and has asserted that in evaluating firm energy and capacity payments, whether pursuant to promulgated tariffs or negotiated contracts, rates must be based on deferrable capacity related costs viewed on a statewide perspective.

To implement this statewide approach, the FPSC chose a "uniform statewide price for QF capacity based on the next planned uncertified unit wherever the need existed in the state."<sup>55</sup> This planned uncertified power plant is termed the "statewide avoided unit." Under the standard offer, the price for capacity payments is based on the value of deferring construction of the statewide avoided unit for a period of time. Thus, if a QF provides firm power to a public utility, the utility can incorporate and utilize the contracted for electricity sales in its expansion plans. Given a sufficient level of firm power available, utilities can defer the construction of additional plants. The FPSC has adopted an approach of treating Florida as one service area. Statewide tariff rates are based on deferring the construction of this unit. Essentially,

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51. See *supra* note 41.

52. FLA. ADMIN. CODE 25-17.825 (2) (1983).

53. *Id.* 25-17.825 (1)(b) (1983).

54. *Id.* 25-17.83 (1) (1983).

55. *Id.* 25-17.83 (1983); Docket No. 820406-EU, Order No. 12634, (Oct. 27, 1983) at 14.

the value of deferral is a calculation of the value of deferring the revenue requirements associated with the new generating plant by a time period, then comparing the difference in annual revenue requirements should the revenue requirements stream began in year  $x$  as compared to beginning in the year  $x + 1$ .<sup>56</sup> In order to calculate the deferral value, one must identify the deferred plant and must ascertain the anticipated in-service date along with the plant's projected costs.<sup>57</sup> The FPSC has designated a jointly owned peninsular Florida base load coal plant consisting of two 700 mega-watt units with an in-service date of April 1, 1992 as the statewide avoided unit.<sup>58</sup> A utility needs to know that QF capacity will not supplement an avoided unit until that unit's otherwise anticipated in-service date. Projected capacity savings, therefore, must be discounted back to present value. The FPSC believes these rules link the purchase price of QF capacity to the value of other supply side alternatives available to a utility necessary to its service obligation. This linkage ensures that cogeneration and small power production will remain a cost effective conservation measure. Thus, the value of QF capacity is linked to the statewide unit from both a timing and a cost perspective.

Although the actual capacity payment calculation is complicated, the Florida approach is very unique. First, the FPSC has included no provision for the payment of existing capacity credits but rather payments are based on deferring future capacity construction. Some states do include such a capacity payment. Under the FPSC's rules, however, capacity payments reflect the avoidance of future potential costs to the ratepayers. Second, the rules attempt to funnel cogeneration capacity to the utilities with the greatest need. The FPSC considered setting capacity prices on an individual utility basis. Under this approach, each utility would set a capacity price based on the value of deferring its next planned uncertified generating units in its service area. Because the price would vary with each utility under this methodology utilities with the earliest in-service date would probably offer the best price and QFs would pursue negotiations with this utility out of economic self interest. This approach would generate differing price and require wheeling if the utility with the greatest need was to receive the needed additional capacity. The approach adopted by the FPSC establishes a

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56. *Id.* at 14-16.

57. *Id.* at 16.

58. Florida Public Service Commission (FPSC), Order No. 13247, Docket No. 830377-EU (May 1, 1984) at 4.



uniform statewide price. Utilities are required to purchase all QF capacity in their service area. The FPSC explicitly stated, however, that it expects a utility to promptly sell unneeded QF capacity in its service area to the utility with the statewide avoided unit in its service area. Further, the Commission expects these transactions to occur at cost thus the utility without the need for QF capacity will incur no costs related to the initial purchase and these costs will not be passed on to their ratepayers. This statewide approach promotes uniformity and fairness in the development of decentralized generation. The Commission believed this approach protects the interests of all Florida ratepayers on an equal basis. This approach also recognizes that decentralized generation confers capacity related benefits on ratepayers only if QFs supply the needed capacity at a cost effective price. That is, capacity payments must be based on a forward looking approach, and decentralized generation should not be an end into itself, but should lead instead to an efficient allocation of resources. Finally, these rules are specifically geared at paying avoided costs and not the additional costs of providing cogeneration and small power production.<sup>59</sup>

The energy payments for firm power are also linked to the statewide avoided unit. Section 25-17.83(6) of the Florida Administrative Code provides that commencing with the avoided unit's anticipated in-service date, QFs receive "the lesser of the as available energy costs of the utility planning the avoided unit or the energy cost associated with the unit itself."<sup>60</sup> This rule requires the payment of "the lesser" because where the planning utility's incremental fuel costs are less than the avoided unit's fuel costs, it is cost effective to base fuel costs on existing plants' marginal costs.

Florida's growth blurs the FPSC's line between payments for energy and payments for capacity. For example, if a utility is adding large amounts of baseload capacity to satisfy growing demands then defining energy costs as the marginal operating costs may underestimate actual energy costs. Under this scenario, capacity is added to avoid the need to use peaking units. Capacity is added because the lower operating costs of base load units more than compensates for high capital costs. Thus, capital costs are incurred to provide energy, not capacity. This conclusion is based on the fact that capital can be substituted for fuel costs in the long run. Accordingly, in this situation some capacity costs are really energy costs, and some avoided capacity

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59. *Id.* at 14.

60. FLA. ADMIN. CODE 25-17.825 (6) (1983).

costs are in reality avoided energy costs.

The statewide approach for both capacity and energy payments is beneficial to the State of Florida and its ratepayers for several purposes. First, the capacity related benefit of decentralized generation reflects the avoidance or deferral of additional generating capacity construction. Thus, capacity payments reflect the avoidance of future potential costs to ratepayers. This approach is also consistent with the FPSC's approach of determining additional capacity need on a statewide basis. This consistency in policy decisions reflects and promotes a uniform reaction to Commission decisions; therefore, policy disputes are focused. Further, this approach permits Florida and its ratepayers to maximize the benefit from QF capacity by channeling geographically dispersed QF capacity to the utility with the most urgent capacity need.<sup>61</sup> Thus, one utility's generation expansion plans may be significantly altered by the aggregate impact of all firm QF capacity as opposed to a potentially slight impact on the generation expansion plans of many utilities by varying amounts of firm QF capacity scattered throughout their separate service areas.<sup>62</sup>

#### D. Purchases by QFs

Section 210(1) of PURPA requires that retail rates charges to QFs for power purchases be just, reasonable and nondiscriminatory against QFs.<sup>63</sup> The FERC interprets the nondiscrimination provision as requiring that QFs be charged the same retail rate as another customer of power and not as a co-producer of electricity.<sup>64</sup> Only if a utility can demonstrate on the basis of adequate data that a QF's service costs are different from other customers, would a different rate be justified and allowed.<sup>65</sup> This provision is particularly critical to many potential industrial cogenerators which feared that their purchase rates would increase if they competed with the utility in electricity generation.

This provision is an essential part of the PURPA scheme if the legislative encouragement of decentralized generation is to be effective. Further, this article asserts that these rates should be adjusted to reflect the load these cogenerators actually place on the system. For ex-

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61. *See supra* note 55, at 18.

62. *Id.*

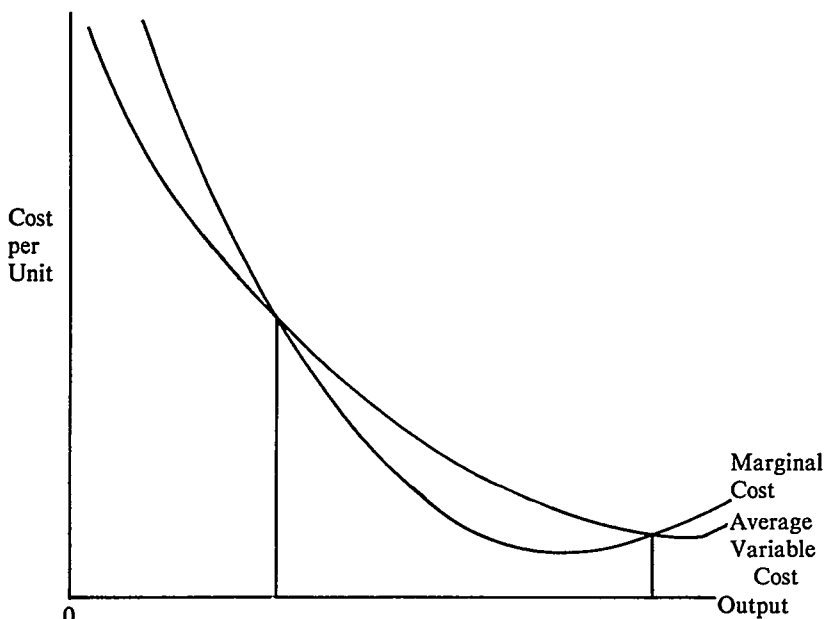
63. 16 U.S.C. § 824a-3 (c) (Supp. 1983).

64. 18 C.F.R. § 292.305 (a) (1983).

65. 18 C.F.R. § 292.305 (b) (1983).

ample, suppose that existing customer rates are based on marginal costs. The issue becomes whether a QF should purchase electricity on a marginal cost as any other customer. The proposed answer is not that it is necessarily in the ratepayer's interest for the QF to purchase electricity based on marginal cost. Traditionally, a class of customer's load factors permit PUCs to estimate what demands this group will place on the utility system. On the basis of this predicted behavior, costs are allocated and charged in a manner to reflect this behavior. This is why different customer classes exist for rate making purposes. Accordingly, a more equitable rate would utilize a rate structure that explicitly tracks utility costs for sales made to QFs rather than a broad structure that applies to all customers. This approach is consistent with the PURPA scheme because unjustifiable discrimination is not allowed and should be guarded against.

Moreover, the rates at which QFs can purchase power are crucial to the development of decentralized generation. For example, if average costs are higher than marginal costs at a given generation point, then it may be reasonable to base all purchase rates on average costs, or at least charge the QF a rate higher than marginal costs as shown in Exhibit 5. This approach would provide additional payments from QFs' power purchases so that QFs would contribute revenues to meet the utility's fixed costs as other ratepayers. This approach, however, may simply encourage QFs to install extra capacity and forego purchasing any electricity from the utility.



The proposed Florida cogeneration guidelines in section 25-17.84 of the Florida Administrative Code do not appear to capture the above underlying economic consequences. However, the rate setting procedure may compensate for any lack of foresight in these rules or lack of specific guidelines.

## V. Effective Implementation of Florida's Approach - A Realistic Analysis

### A. Wheeling

Section 210 of PURPA does not provide QFs with an automatic right to wheel its electricity to other utilities outside the adjacent utility's service area. Further, QFs are not granted the statutory right to request a FERC wheeling order under sections 211 and 212 of the Federal Power Act because such wheeling requests are limited to facilities defined as public utilities, and the thrust of PURPA is not to define cogenerators as utilities.<sup>66</sup> The FERC unofficially has stated that the agency will not move on the issue of forced wheeling for cogenerators. The reason stated for this policy is that no party has demonstrated that forced wheeling will boost the efficiency of electricity generation or distribution.<sup>67</sup> The FERC regulations, constrained by the FERC's authority to order wheeling, do enable a QF to wheel with the consent of the adjacent utility and any other intervening utility.<sup>68</sup> If every utility cooperated in wheeling, QFs could shop around for the most favorable rate throughout the utility grid.

A strong economic incentive to wheel may exist between a QF and an adjacent utility where the adjacent utility does not generate its own power, but rather purchases its power in bulk from another utility. The

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66. 16 U.S.C. § 824 j and k (Supp. 1983).

67. *FERC Will Not Move on Issue of Forced Wheeling, not Even for Cogenerators*, ELEC. UTIL. WK., Aug. 2, 1982, at 1.

68. 18 C.F.R. § 292.303(d) (1983). This section, in relevant part, provides: If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility.

*Id.*

best example of this situation is an electricity cooperative. Assume the adjacent utility buys electricity at rates based on the nonadjacent utility's average embedded cost, but that this rate is lower than the nonadjacent utility's avoided cost. Further assume that the nonadjacent utility's embedded cost rate and avoided cost rate are five and ten cents per kilowatt hour respectively. Assume also that the QF sold its electricity to the adjacent utility for purchases from the nonadjacent facility (i.e., five cents per kilowatt hour). That is, the adjacent utility's purchase price from the nonadjacent utility represents the full avoided costs. Under this scenario, an obvious incentive exists for the QF to wheel to the nonadjacent utility rather than sell to the adjacent utility. Selling QF power to the nonadjacent utility would provide ten cents per kilowatt hour payment to the cogenerator as opposed to a five cents per kilowatt hour if sold to the adjacent utility. The adjacent utility benefits because the facility can continue to purchase power from a stable source. Practically, however, the QFs' incentive may be reduced by the requirement that the transmitting utility be reimbursed for the line losses or by the burden of negotiation costs.

Some PUCs have noted the importance of wheeling to QF development, but few have made specific substantive rulings. The lack of PUC involvement in this area may be based on its position that states lack direct authority to order wheeling because of federal pre-emption. Further, a reasonable position might be that efforts by PUCs to assert direct jurisdiction over wheeling may violate the pre-emption doctrine even if the transaction takes place within the state concerned. This position is based on cases where courts have viewed utility transmission lines, which are interconnected with the grids of other states, as being essentially in interstate commerce and subject to the Federal Power Act. Extending this reasoning then, even if a QF made direct sales to non-utility end users, the utilization of a utility's transmission lines would be subject to federal jurisdiction. This conclusion would be the same regardless of whether the sale itself were a wholesale sale, subject to FERC jurisdiction, or a retail sale, usually subject to PUC jurisdiction. This position is not universal, however, and the matter has not been directly tested in the courts.<sup>69</sup>

The FPSC's rules do not follow this line of analysis, but do follow the minority view. Section 25-17.835(1) of the Florida Administrative Code requires the utility in whose service area the QF is located, and

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69. Lock & Kuiker, *supra* note 48, at 679.

any other intervening utility, to wheel the QFs' electricity to any purchasing utility.<sup>70</sup> The QF, however, must pay for all costs associated with such wheeling including wheeling charges, line losses and inadvertent energy flows.<sup>71</sup> The wheeling utility may petition the FPSC to waive this wheeling requirement if the utility's ability to provide adequate service to its other customers will be impaired or will unduly burden the utility.<sup>72</sup> As aforementioned, the commission believed that the maximum benefit of decentralized generation would be achieved by establishing a statewide wholesale market for QF power. This wheeling requirement again remains consistent with the statewide approach in establishing purchase rates for firm energy and capacity. With respect to firm energy and capacity, the FPSC has attempted to establish a regulatory scheme where QFs would not be concerned with the wheeling because of the established statewide price and where the QF would merely contract with the utility in whose service area it is located. This statewide price would eliminate the need for a QF to shop for the highest price because the highest price would be predetermined. The utility planning the statewide unit would then purchase QF capacity from all other utilities<sup>73</sup> and thus satisfy its capacity needs. Under this regulatory plan, the contractual process is streamlined and the utility whose capacity needs have been alleviated receives the necessary electricity.

Alternatively, the FPSC provided for QFs to deal directly with the utility planning the statewide unit or to market its electrical power to other utilities.<sup>74</sup> Thus, under the FPSC's integrated plan, QFs can negotiate contracts throughout the state for the purchases of their power and are guaranteed a means of delivery. This wheeling requirement should encourage decentralized generation because QFs can effectively shop around for the "best deal" in the state, if one exists.

The financial incentives of shopping around depend significantly on the wheeling charges imposed by the transmitting facility. The FPSC

70. FLA. ADMIN. CODE § 25-17.835 (1983). This section provides in part: "Where such sales are made the utility in whose service territory the qualifying facility is located and any other intervening utility shall make arrangements to wheel electricity produced by the qualifying facility to the purchasing utility." *Id.*

71. *Id.*

72. *Id.*

73. FLA. ADMIN. CODE § 25-17.835, Docket No. 820406-EU, Order No. 12634, (Oct. 27, 1983), at 20.

74. *Id.* at 21. The FPSC believed that "since the ratepayers will experience no direct benefit as a result of wheeling of power . . . the wheeling utility absorb no costs of the transaction." *Id.*

has ruled that QFs be responsible for all wheeling expenses. The FPSC adopted this rule based on the equitable considerations of the transmitting utilities' ratepayers in that the wheeling utility's ratepayers will receive no direct benefit as a result of wheeling QF power; accordingly, the wheeling utility should absorb no costs of the transaction.<sup>75</sup> The actual detrimental effect of this rule to cogeneration development varies if the electricity is wheeled from a QF to a utility in which the statewide avoided unit is located. If the purchasing utility is directly interconnected with the utility planning the statewide avoided unit and has transmission line capability, one could reasonably assert that no wheeling charges should be imposed. If, however, the purchasing utility is not directly interconnected, but must wheel the QF's electricity through a third utility whose transmission capability is not available, then affected utilities should impose wheeling charges on the QF or refuse such wheeling. Further, if the purchasing utility is not directly interconnected, and must wheel the electricity through a third utility with sufficient line capacity, the wheeling utility should impose wheeling charges to recover any resulting costs. The FPSC has adopted the above approach, but expressed doubt as to whether the commission or the FERC has the authority to establish such wheeling rates. The impact of this intrastate approach of decentralized generation depends on the ability of the FPSC to receive a favorable legal opinion from the FERC and possibly ultimately from the courts.

## B. Environmental Impact

In addition to the uncertainty surrounding the FPSC's authority to order wheeling, environmental issues dampen the proposed advantages of a legislative encouragement of decentralized generation. The use of excess waste heat or certain fuels may result in severe environmental damage which would not be permitted by a public utility. Electric utilities are subject to the Florida Electrical Energy Power Plant Siting Act (the "Siting Act") in addition to various Federal environmental requirements. Although inadequate in their operation,<sup>76</sup> these statutory requirements provide a framework for evaluating the environmental

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75. FLA. STAT. § 403.501-519 (1983).

76. See Note, *Florida Electrical Energy Power Plant Siting Act: Perpetuating Power Industry Supremacy in the Certification Process*, — U. FLA. L. REV. — (1984); Note, *Nuclear Power Plant Siting: Additional Reductions in State Authority*, 28 U. FLA. L. REV. 439 (1979).

impact of planned power plants. Moreover, the Siting Act does not even apply to facilities which produce under 50 megawatts which would include many QFs.<sup>77</sup> The same framework for analyzing large power plant production would not apply to cogeneration facilities although the environmental concerns would be identical.

The development of environmental standards for QFs would be equitable to all parties included. First, the economic feasibility of QF production should be evaluated in light of all relevant costs including environmental concerns. Second, a balance must be struck between the encouragement of decentralized generation and the protection of the natural resources. Currently, the balance weighs heavily in favor of decentralized generation. Third, rate payors should not be required to pay avoided costs which include costs of complying with environmental regulations to QFs which do have to comply with the identical regulations. If ratepayers must pay full avoided costs, they should receive the same environmental protection. Finally, such protections extend the intent of the Siting Act. Therefore, current cogeneration and small power production provisions at both the state and federal levels should be modified to effectively deal with the environmental implications of decentralized generation.

### C. Implications of Simultaneous Sales and Purchases

The FERC rules permit a QF simultaneously to sell its entire output to a utility at avoided cost and to buy energy from the utility at retail rates.<sup>78</sup> The consequences of this approach are demonstrated in Exhibit 6. Average costs are less than marginal costs. Existing customer and QF purchase rates are based on average costs such as shown at point x. QFs can sell their output at the higher marginal cost to the utilities which are required to purchase at this avoided cost. Under this scenario, a QF will receive higher payments for electricity sold to the utility (marginal costs) than a QF must pay for electricity purchases (average cost). Thus, the QF may in fact receive a net payment from the utility even though all its output may be used on site.

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77. FLA. STAT. § 403.503(7) (1983). This section provides in part: "Electric power plant means . . . except that this term does not include any steam or solar electrical generating facility of less than 50 megawatts in capacity. . . ." *Id.*

78. 18 C.F.R. § 292.305 (1983).



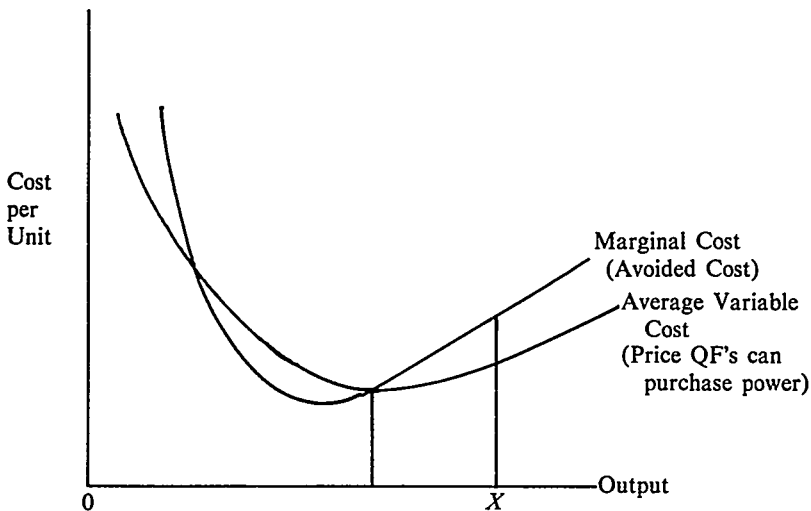


EXHIBIT 6

This approach represents a substantial policy decision and can be justified on several grounds. First, one could assert that cogenerators should not be discriminated against in the purchase of electricity simply because they are co-producers of electricity. In return for being granted a state potential monopoly and guaranteed a specific rate of return on investments, utilities owe an obligation to all customers, including QFs. Additionally, it is arguable that ratepayers are not paying more for the electricity than if the utility produced the power itself because payments to QFs are based on the utility's avoided costs. Finally, this approach provides an additional incentive to the development of decentralized generation which could benefit all parties in the long run.

Notwithstanding the above rationale, there is an inherent injustice in permitting QFs to benefit from simultaneous purchases and sales under certain instances. For example, consider an industrial plant which produces excessive waste heat. The plant had previously obtained the requisite power from the local public utility. Because of the cogeneration rules, the industrial plant installs a power production mechanism which produces electricity far in excess of the plant's needs. Moreover, the plant chooses this oversize capacity to take advantage of the simultaneous purchase and sale requirements and even purchases an inefficient boiler to reduce production costs. Under this scenario, the plant can purchase the public utility's power at the lower average cost, yet force the utility to purchase the plant's power at the higher avoided

cost. The plant benefits from receiving payments far in excess of their power production costs. It is doubtful whether the ratepayers benefit because the utility must purchase the electricity at a higher price, not for just the net amount, i.e., what the plant produced over what the plant purchased from the utility, but for the entire amount produced. That is, if the plant produced eighty megawatts, but only used two megawatts, the utility would have to purchase the full eighty megawatts and not the more logical seventy-eight megawatts. Moreover, all parties suffer if the plant's production facilities cause more pollution than if the utility produced the incremental amount.

The FPSC has adopted both a simultaneous buy/sell approach and a net billing approach under the current rules; however, simultaneous buy/sell arrangements must be available to QFs if they choose.<sup>79</sup> Given the above scenario, more flexibility should be built into the federal and state rules to permit only a net billing approach in the appropriate situation.

## VI. Conclusion

Decentralized generation has many potential benefits. The realization of these benefits, however, depends on an effective implementation of the federal provision by the state PUCs. Additionally, the effectiveness of the rates imposed depend on the specific economic conditions for both the utility and the QF. Notwithstanding this limitation, Florida has adopted a unique and well-reasoned approach to implement these rules by balancing the competing interests of QF development and existing ratepayers. Ratepayers theoretically bear no additional costs under the FPSC's rules yet are still able to reap the benefits of a decentralized generation approach. Environmental issues have yet to be adequately addressed. However, this balancing should result in a well-planned and cost effective development of decentralized generation in this state.

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79. FLA. ADMIN. CODE § 25-17.82 (3), Docket No. 820406-EU, Order No. 12443, (Sept. 2, 1983).