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Technical Memo

ARGONNE NATIONAL LABORATORY

Energy and Environmental Systems Division

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ARGONNE NATIONAL LABORATORY
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ANL/CNSV-TM-33

MASTER

DEVELOPMENT OF A JOINT-COST ALLOCATION MANUAL
FOR INTEGRATED COMMUNITY ENERGY SYSTEMS
PHASE II

Prepared by
✓ Ernst & Whinney
Washington, D.C. 20036

951 1381

for

Energy and Environmental Systems Division
Argonne National Laboratory
under Argonne Contract 31-109-38-4458

April, 1980

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ABSTRACT

The distribution of Integrated Community Energy Systems (ICES) project capital and operating costs among multiple ICES services is of prime concern for an ICES owner and/or operator. The maintenance of adequate revenues from individual services and the commercial viability of an ICES project is influenced significantly by the method chosen for cost allocation. This paper presents an in-depth study of the Alternative Justifiable Expenditure method (AJE). The advantages and disadvantages of the AJE are discussed and a framework is developed for application of the method to the thermal and electric services of an ICES plant. The method departs to some degree from the concepts and procedures used in the cost-of-service allocations by emphasizing the value of ICES services to ICES thermal and electric customers.

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1 INTRODUCTION

This report is the first in Phase 2 of a study for Argonne National Laboratory entitled "Development of a Joint-Cost Allocation Manual for Integrated Community Energy Systems (ICES)." Phase 1, completed in late 1978, was concerned with two major areas:

- What are the theoretical bases for allocating joint costs, and how would they apply to a cogenerating ICES?
- What are the extant methods of allocating joint costs, and how are these methods being implemented for co-generation facilities?

The Phase 1 Report* presented several candidate allocation procedures, and suggested that the "mathematical programming" approach to cost allocation was most promising. With further study, we have concluded that the Alternative Justifiable Expenditure (AJE) approach is preferable and is more likely to be implemented successfully. This report includes:

- A review of the AJE concept and its applicability to the allocation of joint costs in an ICES.
- A description of possible ways of estimating the alternative justifiable expenditures for the outputs of an ICES.
- A discussion of the conceptual and practical problems associated with the AJE approach.

As in Phase 1, the emphasis will be on the economic aspects of cost allocation rather than the engineering aspects. We expect to utilize the services of an engineering firm to develop an engineering-oriented comparison with the AJE approach.

*Development of a Joint-Cost Allocation Manual for Integrated Community Energy Systems, prepared by Ernst & Ernst for Argonne, ANL/ICES-TM-20 (September, 1978).

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2 CONCEPTUAL ISSUES

2.1 THE CONCEPT OF JOINT-COST ALLOCATION

Operation of an ICES results in period costs which must be recovered as revenue from the ICES customers. These periodic costs include expenses for: operations and maintenance, depreciation, taxes, and return on invested capital. Together, these costs comprise the revenue requirement of the ICES as a whole.

To determine prices for the outputs of the ICES (electricity, steam, chilled water, etc.), it is desirable to know the cost of providing each particular output. Some of the costs incurred for the ICES as a whole will clearly be associated with a single output. For example, maintenance expenditures on electrical metering equipment would be associated solely with electrical output. Such costs are termed separable costs, and constitute part of the cost of each output. However, there will be some residual pool of costs that cannot be associated with a single output since an ICES is technically integrated. These joint costs must be allocated to each output in order to determine the individual costs of service. The pool of joint costs may be small or large, depending on the degree of technical integration of the system. It is conceivable that most of the ICES costs may be joint.

The crux of the allocation problem lies in determining a reasonable method of allocating the joint costs to the ICES outputs. Once the joint costs are allocated, the cost of each output is figured by adding that output's separable cost to its allocated share of the joint costs. The resulting cost can then be used to determine prices or rates for that output.

2.2 CANDIDATE ALLOCATION PROCEDURES

Through extensive review of economic, accounting, and public policy literature, we identified numerous proposals for reasonable joint-cost allocations. Our Phase I Report described several of these procedures, and categorized them as "public projects," "cost accounting," and "mathematical programming" approaches to joint-cost allocation. No single procedure was found to be satisfactory on all counts for the purposes of allocating ICES joint costs. However, the concept of "alternative justifiable expenditure," which was developed in connection with the public projects approach, is a valuable starting point for a reasonable allocation procedure.

2.3 THE ALTERNATIVE JUSTIFIABLE-EXPENDITURE CONCEPT

Instead of constructing an ICES, there are several alternative ways of meeting the energy needs of a community. For example, one alternative that would cogenerate electricity and steam is to construct separate electric and steam plants of comparable size. Another alternative might be to purchase electricity from a utility grid, and construct only a steam plant. It is expected that all of these alternatives would be examined in an ICES feasibility study since an ICES should be selected only if it is the most economical method of meeting the community's total energy needs. Data on the cost of the alternatives can be used to guide cost allocations for the ICES.

The data in Table 2.1 show how this is done. Assume that the total cost of cogenerating electricity and steam is \$100. Also assume that the least costly alternative way of obtaining only electricity would cost \$80. This \$80 cost might be for an electric plant, or it might be the cost of purchasing electricity from another source. Similarly, the best alternative for obtaining steam involves a cost of \$40. Note that the cost of the ICES (\$100) is less than the sum of the costs of the least-costly alternatives (\$120); this is a necessary condition for economic feasibility of the ICES.

Table 2.1. Illustration of Alternative Justifiable Expenditure (AJE) Concept

Cost of Cogeneration vs Alternative Costs

Total cost of cogeneration facility.	\$100
Total alternative cost of supplying only electric output	\$ 80
Total alternative cost of supplying only steam output.	\$ 40

Boundaries of Allocation

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	\$80	\$40
Lower bound.	\$60	\$20

The minimum alternative cost for each purpose is termed its alternative justifiable expenditure (AJE). It is the greatest expenditure that could be justified for that purpose in the absence of the ICES. The AJE concept states that the most that should be expended on a single purpose in a multiple-purpose project is the AJE. It follows that the share of the total project costs allocated to a single purpose should be no more than its AJE. Using the AJE, we can establish upper and lower bounds on the allocations for each service. Within these bounds, the sum of the allocated costs must equal the total project costs.

Again referring to Table 2.1, the AJE for electricity is \$80. It would be unreasonable to attribute more than \$80 of the total project costs to electricity since the electricity could be obtained separately for \$80; therefore, \$80 is an upper bound on the allocation to electricity. Assuming that the full costs of the project (\$100) must be allocated, we can compute a corresponding lower bound on the allocation to steam of \$20. Similarly, we can use the AJE for steam to set an upper bound on the allocation to steam (\$40) and a lower bound on the allocation to electricity (\$60). The allocations chosen within these bounds must sum to the total project costs (\$100). The lower portion of Table 2.1 shows these results in matrix form.

The example in Table 2.1 includes no information on separable costs; implicitly, all of the project costs (\$100) are treated as joint. Table 2.2 adds separable cost data to examine how the end result might be affected. It seems reasonable to frame an additional rule: the allocation to each output should never be less than its separable cost, because the portion of the total project costs incurred for that output is at least equal to its separable cost. Using only this rule and the separable cost data, we can construct a second set of bounds on the allocation to each output analogous to the AJE-derived bounds. These are shown in the center portion of Table 2.2. Note that the resulting ranges (\$40-\$90 for electric and \$10-\$60 for steam) are wider than those derived from the AJE rule (\$60-\$80 for electric and \$20-\$40 for steam). Thus, if we combine the results (as shown in the lower portion of Table 2.2), the bounds from the separable cost rule are ineffectual, since they are outside the AJE-derived bounds.* In this case,

*An alternative view is that the lower bounds should never exceed the separable costs; this is discussed at the end of the chapter.

Table 2.2. Illustration Of AJE Concept With Separable Cost Data

Data

Total cost of cogeneration facility.	\$100
Total alternative cost of supplying only electric output	\$ 80
Total alternative cost of supplying only steam output.	\$ 40
Separable cost assignable to electric output	\$ 40
Separable cost assignable to steam output.	\$ 10
Joint cost (total cost less separable costs)	\$ 50

Boundaries of Allocation Using Separable Cost Rule Only

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	\$90	\$60
Lower bound.	\$40	\$10

Boundaries of Allocation Combining AJE and Separable Cost Rules

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	\$80	\$40
Lower bound.	\$60	\$20

use of the separable cost data does not change the allocation, nor improve its precision because the AJE for each output is less than the output's separable cost, plus the project's entire joint cost. If this condition holds, the result can be generalized as follows: the separable cost data add no information not already contained in the AJEs, and thus do not effect the ultimate allocation. This result is proved algebraically in the appendix.

In theory, the AJE for a particular output should always be less than or equal to the output's separable cost, plus the project's entire joint cost.

If this were not the case, then (hypothetically speaking) one could combine the joint portion of the entire project with the separable portion associated with the single output, yielding a single-purpose facility that is less costly than the AJE. But this contradicts the definition of the AJE as the least costly alternative way of obtaining a single output and the estimated AJE would appear too high.

In practice, measurement of AJEs is quite difficult since the analyst must rely on available tariff and plant-cost data to estimate the costs of alternatives. Using such limited information, there is no assurance that an estimated AJE will not exceed the separable cost plus the joint cost. If this situation occurs, the smaller figure should be used as the upper bound on the allocation since it would be unreasonable to allocate more than the separable cost plus the entire joint cost to a single output. To illustrate, assume that the total cost of cogeneration is \$100, and that the AJEs have been estimated as \$80 and \$40 for electricity and steam, respectively. Now assume separable costs of \$65 and \$25 for electricity and steam, respectively, implying a joint cost of \$10. By definition of the AJE, \$80 should be the minimum cost of obtaining only electrical output. But the data suggest that an electric-only plant could be built for \$75 by combining the joint portion of the cogeneration plant (\$10) with the separable portion attributed to electric output (\$65). Consequently, we could build the cogeneration plant (omitting the portion unique to steam output) for less than the presumed AJE of electricity. Therefore, we should use \$75, not \$80, as the upper bound on the allocation to electricity. This is reasonable, since any greater allocation would amount to assignment of a portion of the separable cost of steam to electricity. By the same reasoning, \$35 should be the upper bound on the allocation to steam.

2.4 CHOICE OF A SPECIFIC ALLOCATION

As described above, the AJE concept only establishes bounds on the allocation of costs to each output; it does not yield a definitive allocation. The strict AJE allocation method, as defined in the public projects literature, uses a formulaic approach to the choice of a specific allocation.* The

*U.S. Congress, House, Committee on Public Works, The Allocation of Costs of Federal Water Resource Development Projects, H. Comm. Print No. 23, 82d Cong., 2d sess., 1952.

difference between each output's AJE and its separable cost is termed the "remaining alternative cost." The joint cost is allocated among the outputs in proportion to the remaining alternative cost of each. Finally, the separable cost is added to the allocated joint cost to yield a unique allocation. If this procedure is followed for the example data, it results in allocations of \$68.57 and \$31.43 to electricity and steam, respectively. While this procedure is apparently precise, there is no a priori reason to assume it is "correct," or preferable to any other allocation that falls within the acceptable bounds. Economic reasoning does not establish any other approach to choosing a specific allocation; the most that can be said is that the allocations should be guided by the bounds.

2.5 ALLOCATION OF TOTAL COSTS VS. JOINT COSTS

Application of the AJE approach sets bounds on the allocation of total project costs for each output; however, it is clear that the source of the allocation problem is the existence of joint costs. This might suggest that the allocation should be performed only with respect to joint costs, rather than total costs. In fact, while the AJE approach is based on total cost data, it actually allocates the joint costs (see Table 2.2). First, the method ensures that at least the separable costs are assigned to each output (assuming the AJEs are no greater than the separable costs plus the joint cost). With these portions of the total cost taken care of, the approach operates only on the joint costs. Second, the approach reduces at least part of the uncertainty about the allocation of joint costs. In the example, the initial data show a \$50 pool of joint costs. After the AJE approach is applied (see bottom matrix), there is a range of \$20 in the possible allocation to each output. Hence, the AJE approach has unambiguously allocated \$30 of the joint cost. It does not, however, suggest the manner in which the remaining \$20 should be allocated.

2.6 TIME FRAME OF THE ALLOCATION

In this section, we extend the analysis of ICES costs and AJEs from a single-period framework to a more realistic multi-year framework.

Table 2.3 presents data on an ICES with an assumed life of 10 years.

As before, the data include the annual cost of the ICES cogeneration facility, plus the AJEs for electric and steam output.* Also shown are the present values for each series, discounted at an arbitrary discount rate of 10%. Note that the present value of the ICES costs is less than the sum of the present values of the AJEs, as would be required for economic feasibility.

There are two ways in which the AJE approach could form the basis of an allocation. One way would be to proceed exactly as in the single-period examples developed above, establishing allocation bounds year-by-year with the AJE data; however, this may present problems. Note that in years eight through ten, the sum of the AJEs is less than the project cost. An AJE-based allocation would fail to allocate the year's project cost, because the AJEs are upper bounds on the allocation to each output. Therefore, the AJE-based allocation bounds would have to be relaxed in those years.

An alternative way is to base the allocation on the life-cycle (i.e., present value) cost and the AJE data as presented in Table 2.4. The life-cycle data are used to establish upper and lower bounds on the allocation to each output. The figures in parentheses show the bounds on percentages for the life-cycle project cost. These percentages are then used to allocate project costs in any year. The lower portion of Table 2.4 shows how this would work for the year-eight facility cost data.

Note, however, that use of the life-cycle cost data to establish the allocation bounds does not preclude other problems. Specifically, the allocated costs in a particular period may still exceed the actual AJEs for that period. If prices are based on these allocated costs, it may be difficult to attract or retain ICES customers in the short run. Therefore, some sort of intertemporal transfer may be desired, in order to encourage utilization of the ICES concept for its long-run economies. This would involve shifting allocated costs out of some periods and into others, as in use of life-cycle cost data to develop a level annual cost. However, this might not be feasible due to tax and regulatory policies.

*The AJEs are shown as constant over the period only for ease of computation.

Table 2.3. Sample Data In A Multi-Year Framework

Year	Annual Total Cost of Cogeneration Facility	Annual AJE for Electric Service	Annual AJE for Steam Service
1	\$100	\$80	\$40
2	90	80	40
3	80	80	40
4	90	80	40
5	100	80	40
6	110	80	40
7	120	80	40
8	130	80	40
9	140	80	40
10	150	80	40
Present value of stream, discounted at 10%:			
	650	492	246

2.7 OTHER ISSUES

In this section, we wish to briefly address two criticisms of the concept as presented above. The first criticism is that the AJE approach is "like comparing apples and oranges," since it looks to the costs of alternative energy sources, with different design and engineering characteristics, to guide the cost allocation for a unique ICES. While it is certainly true that the alternative systems are different physically, we believe that the method is sound. Presumably, the customers of each output of the ICES would incur (as a class) the cost of the best alternative way of obtaining energy if the ICES output were not available. Therefore, it is appropriate to use the alternative cost as the upper bound on the costs for which the customers as a class are responsible. If the AJE is not used as the ceiling, the customers of one output might be penalized for the choice of an ICES over the alternatives. The AJE approach ensures that this will not occur.

Secondly, some analysts might be inclined to use only the separable cost as the lower bound on the allocation to each output, saying that any bound in excess of the separable cost is arbitrary. If this suggestion is followed, however, it is impossible to use the AJEs as the upper bounds and still ensure full allocation of costs. Therefore, this view is incompatible with the AJE approach which we believe is based on sound reasoning.

Table 2.4. Application of AJE Concept to Life Cycle Cost Data

<u>Data</u>	
Life cycle cost of cogeneration facility.	\$650
Life cycle AJE cost of electricity.	\$492
Life cycle AJE cost of steam.	\$246

Bounds on Allocation of Life Cycle Costs

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	\$492 (76%)	\$246 (38%)
Lower Bound.	\$404 (62%)	\$158 (24%)

Allocation Percentages Applied to Year Eight Facility Cost (130)

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	\$99	\$49
Lower bound.	\$81	\$31

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3 MEASUREMENT OF THE ALTERNATIVE JUSTIFIABLE EXPENDITURES

3.1 INTRODUCTION

This chapter presents possible measures of alternative justifiable expenditures (AJEs) for the outputs of an ICES. A choice among these alternatives will be deferred until criteria for making the choice are established. As described in the previous chapter, the AJEs can be used to determine the bounds of a reasonable allocation of ICES costs to the individual outputs. Rather than the simple two-output (electric and steam) system assumed in the previous chapter, we will examine a model that recognizes that an ICES may also supply electricity to an area grid, and that electricity from the grid could be used to supplement ICES-generated electricity. Referring to Fig. 3.1, we assume three classes of outputs: customer electricity, steam, and grid electricity (i.e., electricity delivered to the grid in which the ICES is located). As used here, "steam" is representative of the range of thermal outputs an ICES could supply. This is a simplification that does not affect the analysis, which could be extended to accommodate more than three outputs. For each of these three products, an AJE must be determined that can then be used to effect joint-cost allocation.

Fig. 3.1 Three-output ICES Model

The costs that are to be allocated in this framework are only those that pertain to the central ICES facility per se. Allocation of the costs of the distribution system required for the community which the ICES serves is not within the scope of this analysis. For electric service, this is equivalent to limiting the scope of the analysis to the costs that are incurred up to the bus bar.

Two assumptions underlie the ensuing discussion of the measurement of the AJEs for the products produced by the ICES. First, we assume that the alternatives to an ICES are also centralized systems. This means, for example, that the alternative justifiable expenditure for steam output is derived by examining the costs of obtaining steam from a centralized steam-only facility. The possibility of decentralized steam production at each point of end use is not evaluated. In effect, it is assumed that the rationale for centralizing energy production in an ICES is valid for alternative production of the energy outputs. The practical implication of this is that in estimating AJEs we do not need to examine the cost of separate energy systems at each customer location. Thus, we exclude the possibilities of an individual household using its own oil-fired furnace or a building having its own separate heating system as proper alternatives. This is a reasonable assumption both in terms of reducing data requirements and modeling the nature of an integrated energy system.

The second assumption is that the range of options available to estimate the AJE does not include another ICES. This assumption is reasonable since there should be no important cost differences between optional systems. Furthermore, it helps avoid entangling the issue of optional system selection with that of cost allocation, which is our only concern here.

Sections 3.2 - 3.4 discuss the measurement of AJEs for customer electric output, grid electric output, and steam output. The judgements and conclusions presented below must be regarded as tentative, because the proposed measures have not yet been subjected to field testing.

3.2 ALTERNATIVE JUSTIFIABLE EXPENDITURE FOR CUSTOMERS OF ELECTRIC SERVICE

In this section we will examine methods of estimating the cost of meeting the electric needs of customers through alternatives to an ICES.

Two methods will be examined: the tariff-cost method, and the incremental plant-cost method. The analysis will include the possibility that the ICES is grid-connected, so that some of the customers' needs are purchased from the grid.

3.2.1 Tariff-Cost Method

It is expected that most ICES would be grid-connected, or are at least located near electric utility service. For such facilities, an alternative to electricity production through cogeneration is the purchase of electricity from the utility grid. Thus, one measure of the alternative justifiable cost is the cost that would be incurred in purchasing electricity from the utility under the rates it has filed with the state utility commission, with appropriate modifications.

If the ICES is not grid-connected, the AJE is estimated by applying the utility's tariff structure to the ICES load pattern. The tariff that should be employed is that which would apply to large customers with load patterns comparable to the aggregated load pattern of the ICES customers. Choice of the large customer tariff, instead of that which would apply to smaller commercial and residential customers, follows from the assumption that the costs of interest are those incurred in delivery of electricity "in bulk" to the bus bar. Distribution costs, which basically account for the higher unit costs typically charged small customers, are not considered here.

If the ICES is grid-connected, estimation of the tariff-based AJE is somewhat more complicated. At first glance, it might appear that the AJE is figured simply by applying the tariff to the portion of the load that is met by the ICES. However, this would not account for the fixed costs, demand charges, and declining block structures in typical utility tariffs. If some electricity is already purchased from the grid to supply ICES customer needs, the incremental purchase that would be required if the generation from the ICES were not available would not be billed as if it were the only purchase from the utility grid. Instead, the proper AJE is estimated as the difference between the tariff cost of the full requirements of the ICES customers and the tariff cost of the partial requirements (the residual load met through purchases from the grid). As the electrical output of the

ICES full customer approaches full customer requirements, the partial requirements disappear and the method used for non-grid-connected ICES can be seen as a special case of the AJE used for grid-connected ICES, i.e., with partial requirements being eliminated. Table 3.1 presents a typical rate schedule for a large customer of a utility, and a hypothetical electrical needs profile for the customers served by an ICES. The energy profile (total kilowatt-hours during the period) totals across, i.e., production by the ICES plus the partial requirement met by the utility equals the total requirement. The load (kilowatt) profile is not additive, indicating that, at least once during the period, the peak output of the ICES was not available when it could have been used to reduce the demand placed on the utility.

Table 3.2 shows the application of the utility tariff to each column of Table 3.1. The first column simply applies the tariff to the portion of customer needs served by the ICES. The total of the charges in this column is not the appropriate AJE, because the utility would never see this distinct customer pattern; rather, in the absence of the ICES, it would be an addition to the requirements pattern already served by the utility.

Table 3.1 Data For Application Of Tariff Cost Method

Rate Schedule

\$2.00/kW for first 1,000 kW or less of load

\$1.50 per kW for all additional load

2.6¢ per kWh for the first 300 kWh per KW of load

2.2¢ for all additional kWh

Electrical Needs Profile of ICES Customers

	<u>Requirements Met by ICES</u>	<u>Requirements Purchased from Grid</u>	<u>Total Requirements</u>
Load	1,200 kW	2,000 kW	3,000 kW
Energy	350,000 kWh	1,150,000 kWh	1,500,000 kWh

Table 3.2. Typical Rate Schedule Applied To ICES,
Grid And Total Requirements

	<u>Requirements Met by ICES</u>	<u>Requirements Purchased from Grid</u>	<u>Total Requirements</u>
First 1,000 kW @ \$2.00/kW	\$ 2,000	\$ 2,000	\$ 2,000
Additional Load @ \$1.50/kW	300	1,500	3,000
First 300 kWh per KW @ 2.6¢/kWh	9,360	15,600	23,400
Additional Energy @ 2.2¢/kWh	<u>--</u> \$11,660	<u>12,100</u> \$31,200	<u>13,200</u> \$41,600

The second and third columns apply the tariff to the requirements ordinarily met by the utility, and to the total requirements of the ICES customers. The difference of \$10,400 between the totals of these columns is the correct AJE for the electrical service supplied by the ICES. This amount represents the additional charges that would be levied by the utility if the ICES did not meet a portion of the customers' needs. Note that this amount is less than the tariff-based cost of the ICES electrical output (\$11,660). The \$1,260 difference arises from the nonlinearity of utility tariffs and from the noncoincidence of the ICES peak output and the peak in requirements met by the utility.

Tariff Cost Modifications. The tariff-based AJE is subject to modifications to account for any special installation or service costs that would be incurred if purchase of grid electricity were to be a realistic alternative. Charges might be assessed by the utility for extension of the transmission system, or for installation of special devices to protect the grid. The ICES might incur additional costs not included in the tariffs (i.e., distribution equipment), particularly if the utility requires the interconnection to be made at a transmission voltage level. Such front-end costs should be amortized over the life of the ICES, and the periodic expense included in the AJE.

Other Issues. If one attempts to implement the approach using the tariff cost method on a year-by-year basis, it is likely that in certain years the ICES cost will exceed the costs of the alternatives, especially in the early years of the project. This occurs because utility tariffs are generally based on embedded costs of the entire utility plant, which tend to be low relative to current costs if inflation is significant. As discussed above, use of life-cycle cost and AJE data may obviate the problem, since the long-run perspective should eliminate the low embedded costs. However, this would necessitate forecasts of utility tariffs over the planning horizon of the ICES and these forecasts might not be available in the project feasibility study.

A second issue is whether tariffs based on an entire utility system are appropriate for estimation of the AJE. As long as the utility has sufficient capacity to service the additional needs of the ICES customers, use of the system tariff seems reasonable. However, if the system would have to be augmented in the absence of the ICES, it would be theoretically preferable to base the AJE on a separate set of tariffs that accurately reflected the incremental costs.

3.2.2 Incremental Plant-Cost Method

The incremental plant-cost method is the second approach to measuring the AJE of customer electric service. Conceptually, the AJE can be viewed as the cost of the most economical plant that would meet the needs of ICES customers. This plant might be a "stand-alone" unit (i.e., a generating unit independent of any utility) sized to replace the ICES with sufficient backup. In this case, the entire unit would be the "increment," assuming there were no previous stand-alone facility serving the ICES customers. Costs would be estimated from engineering and feasibility studies.

Alternatively, the incremental plant might be that which would be added by the utility if the ICES customer requirements were added to its existing load. The utility would make the adjustment in the most cost-effective manner by adding base capacity or peaking capacity to obtain an optional configuration. The proper increment would depend upon the change in the load profile of the utility when the load of the ICES customers is superimposed.

The incremental plant cost to the utility could be taken from costs of equipment recently brought on line or from cost estimates of new capacity still in the planning stage. This would bring the cost allocation process much more in line with the engineering/planning processes currently employed. Conceptually, this measure of the AJE is attractive since it compares the current cost of the ICES with the current cost of providing electric service only and compares increments specifically designed to provide the same service to the consumer.

The problems with using the incremental plant cost as the AJE are of a practical, not conceptual, nature. First, were these costs determined in the evaluation of the cost effectiveness of ICES cogeneration? Second, if such costs are available, are they for the proper type of capacity? Finally, if they are not currently available, can they be estimated at a reasonable cost?

3.3 ALTERNATIVE JUSTIFIABLE EXPENDITURE FOR GRID ELECTRIC SERVICE

Earlier, we posited a simple three-output model of an ICES in which electricity furnished to the grid is recognized as a distinct output. The AJE for this output is the cost the utility would incur if it did not have this ICES output available. In this section, we discuss two methods of estimating the cost to the utility of replacing the ICES output to the grid.

3.3.1 Short-Run Replacement Cost Method

Energy supplied by an ICES to an electric utility displaces other generation, either from the utility's generators or from the generators of neighboring utilities. The value of such energy to the utility can be set as the costs avoided by reducing generation requirements on the utility's system. The fuel costs which can be avoided are generally identified by engineering studies of the generators involved, in the form of incremental heat rate curves. These incremental fuel costs, plus assigned maintenance costs, are referred to as λ ,* typically x.x mills per kilowatt-hour or equivalently x.x dollars per megawatt-hour.

At any time, the short run replacement cost for an electric utility

costs, are referred to as λ ,* typically x.x mills per kilowatt-hour or equivalently x.x dollars per megawatt-hour.

At any time, the short run replacement cost for an electric utility is the electricity produced by cogeneration priced at λ . Both λ and cogeneration power vary by time of use. The short run replacement cost for a period would be defined by Eq. 1.

$$SRRC = \int \lambda(t) P(t) dt \quad (1)$$

where $P(t)$ is the power produced by the ICES. Using an approximation that the variations in λ during one hour are insignificant, the integral from Eq. 1 can be replaced by the summation of Eq. 2.

$$SRRC = \sum_t \lambda_t E_t \quad (2)$$

Here E_t is the energy produced during the hour, or, equivalently, the average power produced during the hour by the ICES.

λ 's are developed to schedule generation optimally on an instantaneous basis. During an hour, variations in λ can be significant, such as during the sudden shutdown of a large generating unit. Despite such variations, hourly averages for λ are evaluated. This is analogous to utilities reporting their peak-power requirement as their maximum hourly-average demand, despite potentially large fluctuations during the hour.

*Electric utilities dispatch their systems to minimize operating cost.

As a result of this cost-minimization attempt, there exists a well identified short-run marginal cost, or λ (γ), for each utility system or pool. The greatest determinant of λ is fuel cost. λ recognizes changes in fuel cost both with time and between units supplied by different types or sources of fuel. λ further recognizes differing unit efficiencies and differing efficiencies at each operating point on a generator. Most systems also include an allowance for maintenance in this determination of λ . Since marginal cost generally increases as unit production increases, system optimization results in all units being operated at the same marginal cost (which is identical to system λ) or at a constraint point, e.g., the unit's maximum capability. A further refinement which is mentioned, but rarely used, involves incremental transmission losses in the determination of λ , which is essentially the development of localized transmission-adjusted λ 's.

Eq. 2 implies a summation of costs over several discrete time periods. The selection of the appropriate time periods involves the balancing of the cost of sophisticated meters, with the benefit of more accurately measuring temporal variations in lambda. Here it is sufficient to mention some possibilities, which include hour-long periods, two or three periods a day, weekend differentials, or uniform rates for the month.

There is considerable precedent in the utility industry for buying and selling electricity based on lambda, or an approximation to lambda. Many transactions between utilities are priced at the seller's incremental cost (plus an appropriate markup), which formulaically is Eq. 3.

$$IC = \iint \lambda(p_1, t) \, dp_1 dt \quad (3)$$

This is equivalent to charging at the lambdas the seller would experience as the seller changes from no sales to making the transaction. Though Eq. 3 reflects the cost to the seller, it can also be used to reflect the avoided (decremental) cost of the buyer. During periods when a utility has a lambda substantially lower than its neighbors, the utility will market "economy energy," setting the transaction price at approximately the average of the two incremental costs arrived at by Eq. 3. Therefore, short-run replacement cost is generally acceptable to utilities as a pricing mechanism, both when all savings accrue to one company and when the savings are shared between two companies.

The calculation of the short-run replacement cost can be illustrated with the graphs shown in Figures 3.2(A), 3.2(B), 3.3(A), and 3.3(B). The marginal cost curve shows the change in lambda as the utility load changes, and would change with unit availability and weather. The daily load curve is presented in simplified three-hour block form for ease in presentation. Typically, the daily load curve would be blocked hourly. The daily marginal cost curve combines the incremental cost curve and daily load curve, and shows the marginal cost at various times of the day. The excess ICES generation curve presents the power delivered to the grid throughout the day. The calculations for this illustration are shown in Table 3.3. Shown are two calculations of the alternative justifiable expenditure, one based on lambda without the ICES contribution, the other reflecting the integral over

Fig. 3.2.(A) Marginal Cost-Load (MW)

Fig. 3.2.(B) Marginal Cost-Time

Fig. 3.3.(A) Daily Marginal Cost

Fig. 3.3.(B) Cogeneration to Grid

the utility's presumed power level, as in Eq. 3. In this example, the excess ICES output is small relative to the system involved and does not materially affect lambda, the marginal cost of the utility. Reflecting the impact of the ICES on lambda by use of Eq. 3, the short-run replacement cost falls by \$7.20 (i.e., less than 1%).

3.3.2 Average Cost Method

Traditional utility costing procedures allocate the costs of service to the various classes of customers in proportion to various attributes of each class, such as the class energy responsibility and contribution to the system's demand. To the extent that the procedures can be expanded to include a class of "negative" customers (i.e., net suppliers of energy rather than consumers), they can be adapted to the estimation of AJEs. Utilities use class cost of service studies to set (or to justify) rates charged to each class. Accordingly, the "negative costs" allocated to the ICES, viewing it as a negative customer, can be used as an estimate of the average worth to the utility of the ICES' output to the grid, or the AJE.

Table 3.3. Calculations for Short-Run Replacement Cost Method

<u>Time Period</u>	<u>Utility Load (MW)</u>	<u>Lambda (\$/MWh)</u>	<u>Cogenerated to Grid (MW)</u>	<u>AJE from Lambda (\$/hr)</u>	<u>AJE from Eq. (3) (\$/hr)</u>
12 p.m.- 3 a.m.	50	10	1	10	10.0
3 a.m.- 6 a.m.	100	10	1	10	10.0
6 a.m.- 9 a.m.	150	20	2	40	39.6
9 a.m.-12 noon	200	30	2	60	59.6
12 noon- 3 p.m.	250	50	2	100	99.2
3 p.m.- 6 p.m.	200	30	2	60	59.6
6 p.m.- 9 p.m.	200	30	2	60	59.6
9 p.m.-12 p.m.	150	20	1	20	20.0
				360*	357.6*

*Times three to account for

three-hour intervals. \$1,080.00 \$1,072.80

There are two simple methods to implement this approach: the average variable-cost method and the average total-cost method. The former excludes capital costs while the latter includes them. The average variable cost attributable to each class of customers is derived from the product of the variable operating costs (essentially fuel cost and production maintenance cost) and the ratios of the energy responsibility of each class of customers to the utility's total generation, with each expressed in kilowatt-hours. To construct an AJE, the average operating cost is multiplied by the ratio of the ICES contribution to the grid to the utility's total generation, with each expressed in kilowatt-hours. An implication of this method is that the ICES is presumed to be of equal value to the utility as any of its own sources of power.

A deficiency of the average operating-cost method is that it ignores the capital costs of utility operation, as it only allocates the variable costs associated with operations. However, it is possible to factor capital cost into the class cost of service estimation by measuring contribution to peak demand (in kilowatts). To the extent the ICES meets a portion of the peak demand, it can be viewed as a negative contributor to peak, thus offsetting the capital needs of the utility; the worth of the ICES can be established accordingly.

An illustration of the average cost method of calculating the AJE, with and without capital costs, is presented in Table 3.4. This example is highly simplified, neglecting distribution costs, metering expenses, and the

Table 3.4. Average Cost Method

	<u>Utility</u>	<u>Customers</u>	<u>ICES</u>
Annual Energy	500,000 MWh	506,000 MWh	6,000 MWh
Load at Time of Peak	100 MW	101 MW	1 MW
Energy Factor	1.00	1.012	(.012)
Demand Factor	1.00	1.01	(.01)
Variable Costs	\$10,000,000	\$10,120,000	(\$120,000)
Capital Costs	\$ 8,000,000	\$ 8,080,000	(\$ 80,000)

detail with which capacity costs are typically calculated. The first two rows of the table show the energy and demand characteristics of the utility's generation system, customer requirement, and the ICES's contribution to the grid. Using only variable costs, the AJE of the ICES is \$120,000. If the capital costs, presumably incurred to meet peak demand, are accounted for, the AJE increases by \$80,000 to \$120,000.

3.4 ALTERNATIVE JUSTIFIABLE EXPENDITURE FOR STEAM SERVICE

In the context of this report, "steam service" refers to any heat transfer made available to ICES customers, be it in the form of steam, hot water, or chilled water. In this section, we present two approaches to estimating the alternative justifiable expenditure for steam. The possible AJEs for steam are quite similar in concept to those for electric service to the ICES customers. The measures discussed below can be considered in a single-period or life-cycle context.

3.4.1 Tariff-Cost Method

In some large American cities, steam is available as a utility service and is sold according to published tariffs. If the ICES is located within the service area for steam, the tariff could be applied to the steam requirements to develop the AJE. The tariff-based AJE should be adjusted upward to account for special hookup fees and surcharges, if any. Few ICES will be able to estimate the AJE steam service in this fashion, since few will be located in a steam-service area. The potential problems discussed above in using the tariff-cost method for electrical service are also applicable here.

3.4.2 Incremental Plant-Cost Method

The incremental plant-cost method, as outlined above for customer electrical service, involves estimation of the incremental outlays that would be required to replace the ICES generation with either a stand-alone unit or an increment to the existing utility plant. The same two approaches could be used for an ICES within the service area of a steam utility. However, it is more likely that only the stand-alone unit would be a realistic alternative for obtaining steam. The boilers and ancillary equipment to

generate steam would necessarily be sized to provide sufficient backup to ensure system reliability. The costs of this stand-alone steam generation would constitute the AJE. Of course, use of this approach is predicated on the assumption that a centralized provision for thermal energy is an economically justifiable alternative to use of decentralized equipment. Normally, the calculation required to justify this assumption would be a component of the ICES feasibility study. The data required to estimate the costs of stand-alone steam generation are also likely to be available in the feasibility study.

3.5 SUMMARY

This chapter has presented several possible measures of the AJE for the three products of an ICES cogeneration unit as the basis for establishing the cost allocations to each product. These measures can be constructed both on an annual basis and on a life-cycle basis. Naturally, the life-cycle AJEs require greater amounts of information; but in some situations the life-cycle approach should avoid or mitigate some problems that occur when the cost calculations are made for a single year or other brief periods.

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4 CRITERIA FOR SELECTING MEASURES OF THE ALTERNATIVE JUSTIFIABLE EXPENDITURES

4.1 INTRODUCTION

Criteria for selecting a method or methods for measuring the alternative justifiable expenditure (AJE) are discussed in this chapter. The material that follows is organized around the proposed criteria, and the applicability of each to the classes of ICES outputs is discussed in broad terms.

4.2 DATA AVAILABILITY

Perhaps the overriding criteria for choosing among the candidate AJE measures is data availability. If the data is not available at a reasonable cost, further consideration of a particular method is excluded. Thus, in addition to serving as criteria for weighing choices, it is a constraint that determines the feasibility of a method in an absolute sense.

As indicated in Section 3, much of the data required to implement the proposed methods should be available in the feasibility study for the ICES. It is probable that a thorough feasibility study (i.e., one which examines all of the alternatives for meeting the community's energy needs before deciding on the ICES as the appropriate choice) would include cost projections for the ICES and the alternatives over the useful life of the system, in addition to projected load profiles. However, data available from the feasibility study should not necessarily be accepted at face value. The analyst undertaking the cost allocation project should review the assumptions underlying the feasibility calculations before incorporating the data in the AJE application. In addition to encompassing any forecast data, this scrutiny should include the choice of such parameters as the useful life of the ICES and the appropriate discount rate for converting streams of revenues and costs to present values.

Data that are not likely to be in the feasibility study include information on the separable costs that can be attributed to each of the ICES outputs. As discussed previously, separable cost data are not essential to implementation of the AJE approach. However, in certain cases such data may override the upper allocation bounds established by the AJEs. In any

event, separable cost data must be developed through detailed engineering-oriented analysis of the proposed facility.

Another class of data that may not be readily available includes information specific to the electric utility and grid to which the ICES is connected (or, in the case of a non-grid-connected ICES, the nearest utility and grid). Clearly, such information is required to determine the AJE for grid electricity under any of the procedures discussed in the preceding chapter. In addition, one variant of the incremental plant-cost method involves estimating the costs of meeting the ICES needs through an increment to the existing utility plant, rather than a stand-alone facility. Cost and operating characteristic data will only be available if cooperation from the utility is forthcoming.

In general, the criteria of data availability does not automatically suggest acceptance or rejection of particular AJE estimating procedures. Knowledge of the circumstances specific to an ICES and the feasible alternatives is required before the criterion can be applied to weigh the merits of each candidate procedure.

4.3 STABILITY OVER TIME

A second criterion that can be applied to the candidate measures of the AJEs is stability over time. Do the allocation bounds differ substantially from one year to the next? Instability is undesirable because use of the ultimate allocations for pricing purposes may result in confusing price signals.

In Section 2.6, the basic one-period analysis was extended to a multiple-period framework. As part of that discussion, two ways of implementing the AJE approach in a multiple-period context were discussed. In either case, one possible source of variation in the ultimate allocation bounds is the total cost incurred for the ICES. If this is not constant from year-to-year (and there is no reason to presume it would be constant), then the allocation bounds will fluctuate, regardless of the choice between a year-by-year or a life-cycle analysis. The only way of dealing explicitly with this source of variation is to use some sort of intertemporal transfer scheme to smooth the cost between periods.

The other possible sources of variation are the AJE data. However, this type of variation will only arise if the year-by-year approach is taken; the life-cycle approach obviates this problem because an invariant set of proportions is applied to the ICES cost data.

Assuming the year-by-year approach is adopted, we can hypothesize that tariff-based AJEs will tend to be relatively stable since public utility regulatory bodies are inclined to disallow requests for significant year-to-year changes in the structure and level of rates.

AJE estimates that are based on actual costs incurred for alternative plants are not likely to exhibit the same stability. For example, assume that an AJE for steam is derived from cost estimates of constructing and operating a stand-alone steam plant. Over the relevant time horizon, start-up costs may result in relatively higher costs in early years. Also, expected maintenance and repair costs will not necessarily be spread evenly over the life of the facility.

4.4 UPDATING REQUIREMENTS

This criterion refers to the technical ease and cost of updating the AJE data, and the frequency at which updating should be performed. In order to implement a life-cycle approach, a set of AJEs must be estimated for each year in the time horizon. Estimation of the AJEs necessarily involves predictions of future costs, tariffs, load profiles, etc. As time passes, and the inaccuracy of some of the forecast data is revealed, it may be desirable to update the data based on the latest available information, and thereby change the proportions for the allocation bounds that were established at the outset.

With the year-by-year approach, updating is more or less a continual process, unless it is decided to forecast all the year-by-year AJEs at the outset, in which case the issues are the same as in the life-cycle approach.

To a large degree, the updating criterion is similar to the data availability criterion, as it involves a weighing of the cost and effort required to obtain the requisite data for each of the AJE measures (see Section 4.2). In addition, we may hypothesize that the use of tariff-based AJEs could impose a requirement of more frequent updating since tariff data

is readily available (i.e., "out in the open") and any discrepancies between the forecasted tariffs used to establish the AJEs and the actual tariffs would be readily apparent. In contrast, discrepancies involving cost-based AJE data may not be obvious without a full-scale effort to re-estimate costs.

4.5 TECHNICAL SKILL REQUIREMENTS

Another criterion related to data availability involves the level and mix of technical skill required to estimate each of the AJEs. Implicitly, the technical skill requirements affect the cost of obtaining the necessary data. Other things being equal, it is desirable to minimize the burden of obtaining the data.

In general, we would expect that estimating AJEs from plant-cost data would require a higher level of technical input than tariff-based measures. However, it is reasonable to expect that the technical burden of any method would be comparable to that faced in the feasibility study for the ICES.

4.6 SPECIFICITY

The criterion of specificity refers to the level of judgement that must be employed to arrive at the allocation bounds. We have argued that a benefit of the AJE approach is that it does not specify exact allocations; rather, it indicates a range of acceptable outcomes. Within the established bounds, non-economic policy considerations can then legitimately influence the ultimate outcome. However, it is desirable that the figures used to justify the bounds be as unequivocal as possible in order to minimize controversy about the results. If the chosen measures of the AJEs are suitably specific, different analysts working from the same data would be expected to produce comparable results.

As noted earlier, judgement is inherent to all methods since forecasts of costs and load profiles are required. The level of judgement required in the other aspects of each method is not clear at this time.

4.7 SUMMARY

In this chapter we have presented several criteria that should be applied to the selection of methods for measuring the AJEs for each of the ICES outputs. For some of these criteria, we were able to discuss a priori hypotheses as to their application to the proposed AJE measures. Without the basis of experience, the measures cannot be fully evaluated at this time. These criteria will be referenced again in the subsequent portions of this study, in which the AJE approaches will be evaluated using real-world data.

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APPENDIX

PROOF THAT SEPARABLE COST DATA DO NOT
AFFECT AJE-BASED ALLOCATION

Let T = total cost of cogeneration project

A_e = AJE for electric output

A_s = AJE for steam output

S_e = separable cost attributable to electric output

S_s = separable cost attributable to steam output

Since the total cost equals the separable costs plus the joint cost,

$$T - S_e - S_s$$

is the joint cost.

Assume: For each output, the AJE must be less than or equal to its separable cost plus the joint cost. (See text for justification of this assumption.)

This assumption translates into two inequalities:

$$A_e \leq S_e + (T - S_e - S_s) \quad (1)$$

$$A_s \leq S_s + (T - S_e - S_s) \quad (2)$$

Using only the total cost and AJE data, we can define upper and lower bounds on the allocation to each output:

Boundaries of Allocation With AJE Rule

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	A_e	A_s
Lower bound.	$T - A_s$	$T - A_e$

Using only the total cost and separable cost data, we can define another set of bounds:

Boundaries of Allocation With Separable Cost Rule

	<u>Electric Cost</u>	<u>Steam Cost</u>
Upper bound.	$T - S_s$	$T - S_e$
Lower bound.	S_e	S_s

From inequality (1),

$$A_e \leq T - S_s. \quad (3)$$

This means that the AJE-based upper bound on electricity will always be less than or equal to the separable cost-based bound. Therefore, combining the two bounds will not change the AJE-based result.

From inequality (2),

$$A_s \leq T - S_e. \quad (4)$$

This means that the AJE-based upper bound will always be less than or equal to the separable cost-based bound. Therefore, combining the two bounds will not change the AJE-based result.

Rearranging inequalities (3) and (4),

$$S_s \leq T - A_e \quad (5)$$

$$S_e \leq T - A_s. \quad (6)$$

These imply that the separable cost-based bounds will always be less than or equal to the AJE-based bounds.

As a group, inequalities (3) through (6) imply that the separable cost-based bounds will always "bracket" the AJE-based bounds; the latter will always lie inside the former. Therefore, use of the separable cost information will not change the allocation bounds that follow from the AJEs, nor improve their precision.