Cost of Reliability:
A Discussion and Analysis
of

FP&L's May 16 Outage

by

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Department of Electrical Engineering

February 20, 1978

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Interruption

On May 16 of this year, the loss of Turkey Point #3 began a series of outages which lead to a power interruption that affected 1,300,000 customers over a period of 4-4 1/2 hours. This paper will address both the reliability issues as well as the related cost issues of this outage to emphasize the need for more theoretical work in the area of Economics of Electric Energy Reliability. The discussion will intentionally be simplified to highlight the basic nature of quantifying the cost and worth of power system reliability. However, to compensate for the quantitative shortcomings and to point the way for future extensions, the last section will be devoted to a brief discussion of available data as well as the need for analysis of disaggregated data to achieve more meaningful results.

The paper contains three sections: Review, FP&L Analysis, and Unresolved Problems. The Review section presents a brief overview of power system reliability analysis in addition to a discussion of how such analysis has been used in the analysis of the economics of energy reliability. The second section is devoted to describing and analyzing the outage that took place within FP&L's system, with emphasis on a quantitative assessment of the Loss-of-load Probability and <u>Cost/Benefit</u> ratio as a function of availability of East-West transmission capability and generation capacity in the SMSAs of Dade, Broward, and Palm Beach counties. Finally, the third section is devoted to a discussion of problems to be addressed if a useful cost of reliability methodology if to be developed.

1. <u>Review</u>

Although the literature abounds with papers on power system reliability analysis, very little applied work of any quality has been done which would enable electric utilities to determine what, when, and where components should be added to their systems to achieve a desired level of reliability.

Such a level of reliability presumably should be where the incremental benefits to customers just equal the incremental costs. It is necessary to have a methodology that can relate the cost/benefit of a given system realization (as reflected in customer preferences) to the performance and availability of that system realization; to date no adequate methodology exists. However, both the Electric Power Research Institute (EPRI) and the Department of Energy (DOE) are conducting funded research in these areas. Of particular interest is the recent DOE research activity in the area of system effectiveness analysis promoted by the author while on leave with the Energy Research and Development Administration, now a part of DOE.[1]

The measures of power system reliability currently in use are indices developed from analyses performed on a sub-system basis. Generation, transmission, and distribution system planners use very different approaches to evaluating the reliability of their individual sub-systems, and, unfortunately, often ignore, out of necessity, the reliability characteristics of all other sub-systems. For example, generation system planners evaluate the need for more generation based on an index called loss-of-load probability, LOLP, which is the <u>probability</u> that <u>loss-of-load</u> will occur due to insufficient generating capacity, assuming that all generators and all loads are connected to a common point. Similarly, distribution system planners evaluate substation reliability using the frequency, f, and duration, d, of outages assuming that the source of power to the substation is perfectly reliable. A similar situation occurs with transmission planners when, in the rare case, probabilistic reliability analysis is even used. It is more common for transmission planners to assess the reliability of the transmission network using direct simulation techniques which are deterministic, and hence, do not produce indices of reliability that are readily related to the generation and distribution system probabilistic indices. In short, because of the divergent nature of the methodologies developed and employed by the utility industry to assess system reliability, little progress has been made to establish a bona fide and useful theory of the Economics of Electric Energy Reliability.

Probabilistic transmission system reliability methods, when used, model the power system in its entirety by arcs whose flow capacities are equal to either the maximum current or maximum power handling capability of the associated element.[2] It is this technique that is employed in the next section to analyze the FP&L outage. Although the approach is basically a graph theoretic method, which ignores Kirchoff's voltage laws, it facilitates the inclusion of both the generation as well as the transmission system in calculating LOLP. Furthermore, the expression for LOLP lends itself to an analytical description of the roles the individual sub-systems played in the May 16 outage as well as the worth of the individual sub-systems as perceived by the customers, albeit in a crude fashion.

Telson, in his recent paper on the "Economics of Alternative Levels of Reliability for Electric Power Generation Systems" partially addressed the issues of concern in this paper.[3] Unfortunately, his approach ignored, as is common, the reliability characteristics of the transmission grid. The emphasis in the paper was to show that because of the excessively high levels of system reliability the cost of an additional unit of energy far exceeds the revenues to be collected for that same unit of energy. Telson suggested that if lower reliability standards were adopted, the marginal cost of producing a unit of electric energy would approach the marginal benefit to be derived from having an additional unit of energy available for use by society.

Others have attempted to assess the cost of unreliable service by analyzing the cost of unserved energy by customer type.[4] Note that the quest for a useful approach to assessing the economics of electric energy reliability is not new; Dean's and Lyman's papers of 1938 and 1933 address similar issues.[5,6]

2. Analysis of FP&L Outage

On May 16, 1977 at 10:08 a.m., with (1) the major East-West 230/500 kV line from Andytown (near Fort Lauderdale) to Orange River (near Ft. Myers) out of service for testing (see Fig. 1), (2) Turkey Point #4 Nuclear Unit out of service for refueling, and (3) 2187 megawatts of Combustion Turbines, Fossil Steam, and cold-standby units unavailable for service,[7] Turkey Point #3 Nuclear unit tripped.[8] The increased deficiency in generation in the South Area (Dade & Broward counties) produced heavy flows across the intact East-West 230 kV Ft. Myers-Ranch (near West-Palm Beach) line and the intact North-South 230 kV Pratt & Whitney-Ranch line. The subsequent loss of the heavily loaded 230 kV Ft. Myers-Ranch line separated the South and Lower-East areas from the West, Upper-East and North areas. The net effect of the outage sequence was the beginning of a 4-4 1/2 hour interruption involving 1,300,000 FP&L customers from Ft. Pierce to Key West.

It is evident from the reports issued by FP&L as well as the Public Service Commission, that the following factors contributed to the interruption:

1. Simultaneous testing of a major East-West line and refueling TP#4.[8]
2. Unavailability of 2187 MW of combustion turbines, fossil, and cold stand-by units.[7] (23 outages totaling 2.5 min.)
3. Poor performance of the 230 kV Ft. Myers-Ranch line.[8]

In order to attempt to quantify the value of having adequate transmission to the West Coast, and adequate capacity in the North, West and South areas, the system model depicted in Fig. 2 will be modified as shown in Fig. 3. Fig. 2 portrays the actual loads that existed in the various areas of 10:08 a.m. on May 16 except in the North and East areas, where the load in the North area was combined with the installed capacity of the North and East areas to create an equivalent area having an installed capacity of 2271 MW and a load of 715 MW. This reduction which ignores ties to neighboring utilities was performed to simplify the analysis and to highlight the more important features of the system.

In fig. 3, the area loads have been subtracted from the West and North/East area's installed capacities to create the net maximum capacities for these areas of 1151 MW and 1556 MW respectively. The maximum capacity in the South area with TP#4's capacity (681 MW) removed, since it was on maintenance, is 3855 MW -- the integrity of the load in the South area is retained for reasons of computational simplicity.

In Fig. 4, the effects of line unavailability as well as capacity unavailability are shown next to the corresponding elements, i.e., the capacity of the West area is decomposed into two parts, where each part is assumed to be available p and q percent of the time, to reflect the unavailability of the combustion turbine etc., capacity on May 16. Similarly, the two East-West lines are assumed to have two capacity states; either the lines are in and can carry their indicated rate power-flows or they are out and can transmit no flow. The North/East area is modeled by two capacity states to reflect the reduction in capacity of the North/East area if the lines on the Pratt-Whitney to Ranch row fail. Finally, the South area capacity is modeled using four capacity states to reflect the unavailability of Combustion Turbines etc., as well as the loss of TP#3.

Applying a combinatorial, probabilistic method to this composite generation and transmission problem the analytical expression describing the probability of loss-of-load, is

$$\text{LOLP} = q_g[q_1q_3 + q_2q_3q_L\ (1 - q_1)]$$

where q_g = normalized percent of time the maximum installed capacity of the South area is only 1991 MW instead of 3855 MW with <u>TP#4 on maintenance</u>.

q_3 = normalized percent of time the capacity of the North/East area is reduced to 546 MW due to the outage of the Pratt-Whitney to Ranch line.

q_4 = normalized percent of time the capacity and West areas are reduced due to unavailable Combustion Turbine etc., capacity.

q_1 = normalized percent time TP#3 is unavailable for service due to a forced outage.

q_2 & q_L = normalized percent time the 230 kV Ft. Myers-Ranch line and the 500 kV Andytown-Orange River line are unavailable, respectively.

Table 1 was created by substituting into the LOLP expression typical values for q_1-q_3, and letting q_g and q_L vary from 0 to 1 to simulate the loss of generation in the South area as well as the loss of the 500 kV line. If the 500 kV line and the Combustion Turbine capacity in the West and South areas are <u>not</u> available, as was the case on May 16, 1977, the LOLP expressed in hours/year is 4.5 <u>hrs</u>/year -- which agrees with the actual outage period.[9] If the 500 kV line had been available an improvement in reliability of approximately 7% would have resulted. In contrast, however, if adequate capacity had been available in the South area a 95% improvement in reliability (.2256 hrs/yr) would have resulted.

Assuming for the purpose of this preliminary investigation that only general trends are of interest, by dividing the number of employed people in the South area (Dade, Broward, and Palm Beach counties) into the total personal income of both wage earner and proprietors, we obtain an estimate of $5.80/Hr, for each of the 1,013,300 employed people in the South area. Stated differently, every hour some 5.8 million dollars are earned in the South area. Assuming that a power outage of one hour results in the complete loss of the 5.8 million dollars, the cost to FP&L customers of the unavailability of the 500 kV line and adequate capacity would be $26,175 million. To reduce this loss by providing adequate generation in the South area, at least 700 MW of generation would be needed, and at $150 - $1000/KW, depending on capacity type, the cost would be $105 - $700 million. Assuming that the fixed charge rate is 25% (which is perhaps a little high) and that the benefits are the same for each year of the plant's life, then the cost/benefit ratios vary from 5.4 to 9.8 depending on the type of capacity and its associated availability. Immediately one can conclude that spending 5.4 to 9.8 dollars for every dollar saved in lost earnings is suspect indeed. The Cost/Benefit ratio for the 500 kV line is the lowest at 3.48; based on a line cost of $.25 million/mile for the 100 mile long line. Figure 5 depicts the relationship between revenue required from customers and savings in lost earnings, both as a function of LOLP. For example, if the reliability were improved from a LOLP = 4.513 $\frac{\text{hrs}}{\text{yr}}$ to a LOLP = 2.256 $\frac{\text{hrs}}{\text{yr}}$ then, from the bottom curve and the left-hand axis, a savings of 13.09 million dollars in lost earnings could be realized. However, to improve the reliability using a Mid-range unit would cost the customers in increased revenue some 70 million dollars as depicted by the upper curve and the right-hand axis.

To carry the analysis one step further, Fig. 5 suggests that for power-outages of less than 1 hr/year, it would be economic to add a 700 MW base load unit only if it resulted in increased productivity equivalent to 25.86 hrs at the existing production rate. Similarly, for power-outages of 1-3 hrs, it would be economic to add a Mid-range unit only if it resulted in increased productivity equivalent to 9.81 hrs at the existing production rate. Viewed in a different light, one could also argue that purchasing a 700 MW base-load unit to reduce the LOLP to .2256 hrs/year makes economical sense to the customer only if every hour of an interruption produces a 7 hr loss in productivity. Certainly in some industries, such as the plastics or chemical industries, such a situation is very possible. Similar interpretations can be made for the other points on the curve shown in Fig. 5. In addition, to assess the value of building new electric facilities to improve reliability, it is meaningful to evaluate the increased earnings per hour required to justify capital expenditures for reliability improvement. Figure 6 provides this information with the corresponding LOLP also indicated. Again, the curve illustrates the impact the various investment decisions will have on the employed people in the three SMSAs considered. Furthermore, if we make the assumption that only unity Cost/Benefit decisions will be made then the worth of each investment shown on the x axis is the corresponding value on the y axis in Fig. 6. For example, the expenditure of 175 million dollars each year, which is the customer's annual cost of a 700 MW base-load plant, would or should result in at least $88,000/hr increase in wages for all employees and proprietors in the SMSAs considered.

If, however, the construction of the 700 MW plant does not result in an increase of $88,000/hr then one can only conclude that such an expenditure is not justified for the customers as a whole. This does not mean, of course, that for any given customer or any given type of customer that such an investment to improve reliability is not justified.

3. Future Extensions and Problems

From the analysis of the FP&L outage, it should be clear that the value of increased reliability is not always positive for all end-use sectors taken as a whole. The expenditure of 175 million dollars to receive benefits of only 24.86 million speaks for itself. The actual dollar amounts are hardly important here, but what is important is that a better understanding of the value of reliability be obtained for each end-use sector as well as individual customers within sectors.

It is this writer's opinion that the high Cost/Benefit ratios are a direct result of "relative" saturation effect occurring in the benefit curve in comparison to the cost-curve at levels of high reliability, as shown in Fig. 7. Stated more bluntly, it appears at this time there is a tremendous mismatch in degree of sophistication between the power-supply and most end-users. In FP&L's system approximately 89% of their customers are residential, many of whom are simply probably insensitive to minor degradations in today's reliability standards. Only .33% of FP&L's customers are classified as Industrials where one would expect to find less of a mismatch between the level of reliability required versus that provided. For completeness, almost 9.5% of FP&L's customers are commercial which is the category that appears to bridge the gap between residential and industrial customers in terms of reliability. Typically, in Florida, the residential KWH consumption is equal to the sum of the commercial and industrial consumption. Further, there are generally ten times more residential customers than commercial and three hundred times more residential customers than industrial customers. These facts suggest that the demand for high reliability emanates from a small number of industrial customers that consume 25% of the electric energy. Figures 7 and 8 attempt to depict the situation, where Fig. 8 strongly suggests that the sensitivity of benefit versus cost ranges from zero to unity. The high technology customers, who are perhaps more willing to pay for high reliability, range from .5 to 1.0 and the low technology customers range from 0 to .5. Because of the dominance of low technology end-users, the overall system appears insensitive to improvements in reliability.

For future studies, disaggregation of industrial and commercial data is necessary. Data are readily available to go one step beyond this initial investigation.[9] Obviously, with adequate data for each of the end-use sectors as well as the sub-sectors, a more realistic economic model of outage impacts on wages and other income could be developed. The model used in the FL&L example aggregated the sectors to the point where the economic model did not properly represent high technology or reliability sensitive customers. It is anticipated that in future studies, the use of a more disaggregated economic model will reveal a spectrum of Cost/Benefit ratios which will suggest the desirability of system designs that exhibit different degrees of reliability for different end-use sectors and sub-sectors, where different end-users would pay on the basis of the quality of service they receive.

Another dimension that should be added to the analysis is time. Since it is quite reasonable to assume that lost productivity due to power outages is not necessarily felt immediately by all end-users, but is delayed varing amounts by different end-users, time value of money notions could be incorporated into the analysis. A related issue assumed away in the FP&L analysis is the true distribution of economic loss due to an interruption. For simplicity, in the first-cut FP&L estimate, the economic loss was distributed equally among all wage earners and proprietors. In actuality, the economic loss is probably not distributed equally; proprietors probably absorb the greatest percentage of the loss initially with the wage earners feeling the economic effects of the interruption over some future period in the form of lost real output. Thus, the mechanisms determining the distribution of the economic impact of an interruption need to be better understood before a methodology can be developed for use by electric utilities in determining future plans.

The estimated income losses used in this study do not take into account the cost of inconvenience or other socioeconomic consequences of interruptions. Furthermore, external effects of interruptions; although important, have been neglected. Such effects would include rioting, looting, and the like, all of which recently occurred during the Consolidated Edison blackout.

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9. Florida Statistical Abstract, 1976. Prepared by Bureau of Economic and Business Research, College of Business Admin., Univ. of Florida.

Table 1

LOLP	q_1	q_2	q_3	q_4	q_g	q_L	Lost Earnings x 10^6
4.513 $\frac{hr}{yr}$	.12	.01	.004	1.0	1.0	1.0	26.175
4.200 $\frac{hr}{yr}$	"	"	"	"	"	0.0	24.38
3.78 $\frac{hr}{yr}$	"	"	"	"	0.9	"	21.92
2.256 $\frac{hr}{yr}$	"	"	"	1.0	.5	1.0	13.08
.2256 $\frac{hr}{yr}$	"	"	"	1.0	.05	1.0	1.30

LOLP = Loss-of-Load Probability

q_1 = Outage Rate of TP#3

q_2 = Outage Rate of 230 kV Line

q_3 = Outage Rate of Pratt-Whitney Line

q_4 = Outage Rate of Gen. in West Area

q_g = Outage Rate of Gen. in South Area

q_L = Outage Rate of 500 kV Line

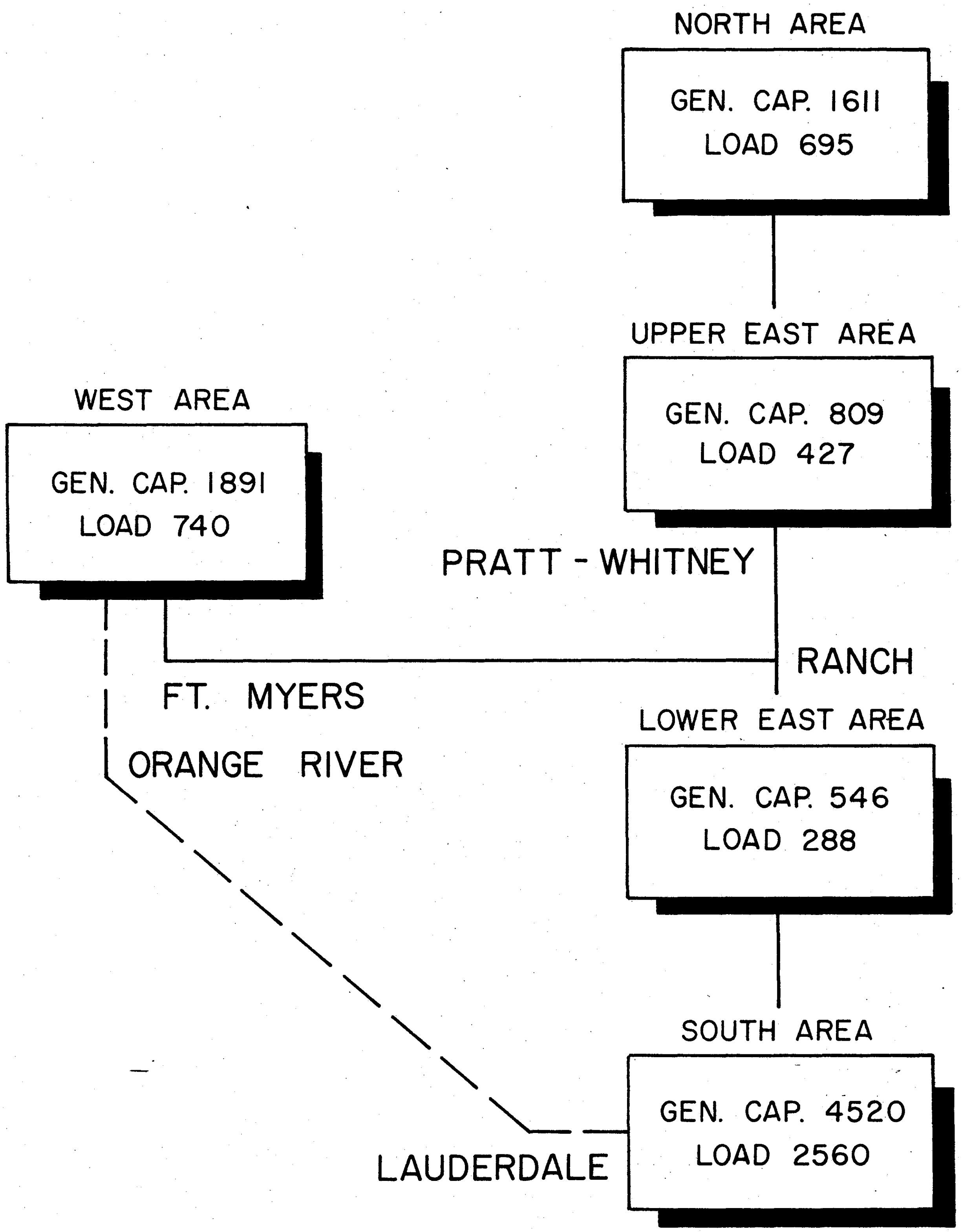
NORTH AREA
GEN. CAP. 1611
LOAD 695
UPPER EAST AREA
GEN. CAP. 809
LOAD 427
WEST AREA
GEN. CAP. 1891
LOAD 740
PRATT - WHITNEY
RANCH
FT. MYERS
ORANGE RIVER
LOWER EAST AREA
GEN. CAP. 546
LOAD 288
SOUTH AREA
GEN. CAP. 4520
LOAD 2560
LAUDERDALE

FIGURE 1

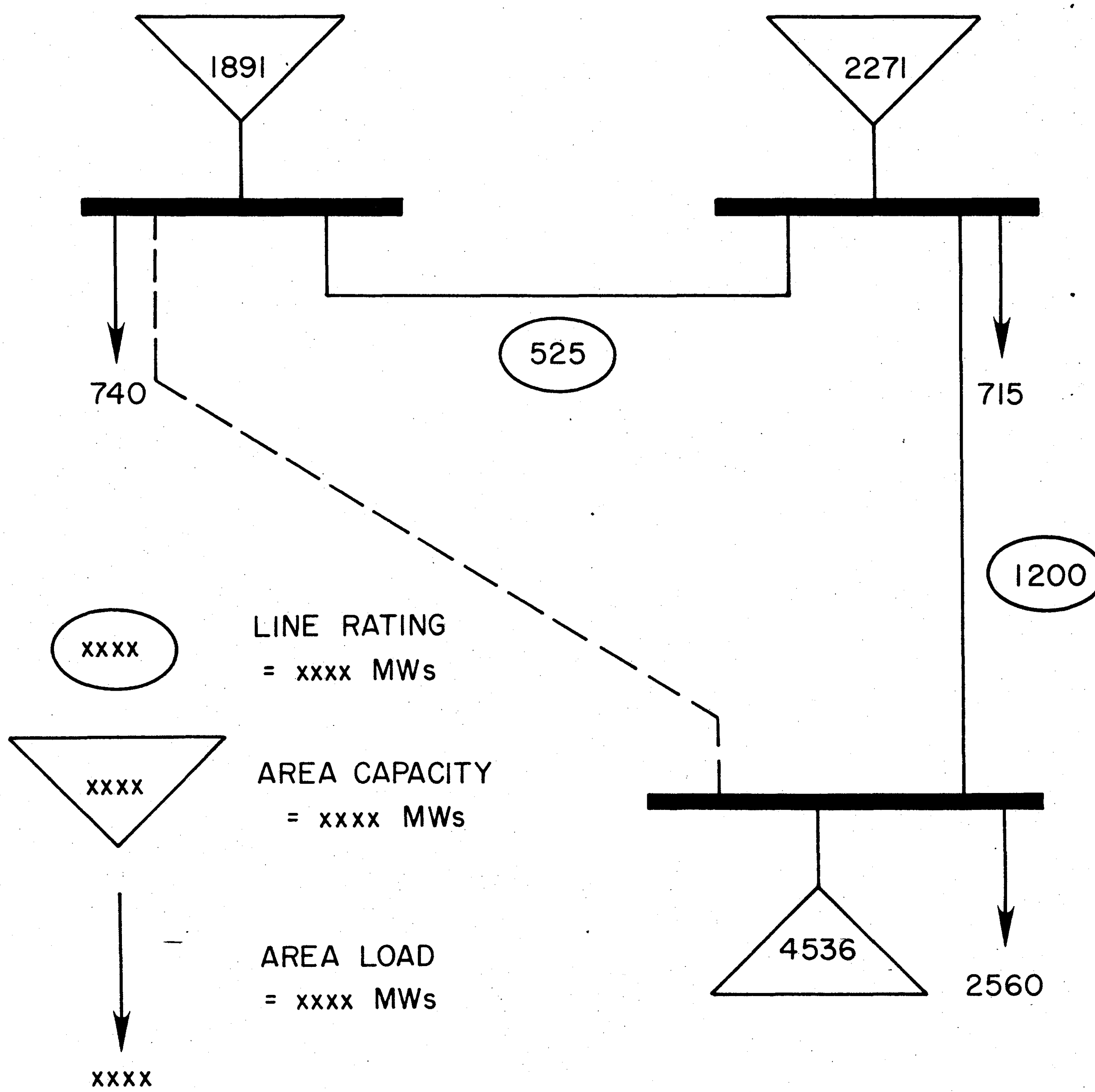
1891
2271
740
525
715
1200
xxxx
LINE RATING
= xxxx MWs
xxxx
AREA CAPACITY
= xxxx MWs
4536
AREA LOAD
= xxxx MWs
2560
xxxx

FIGURE 2

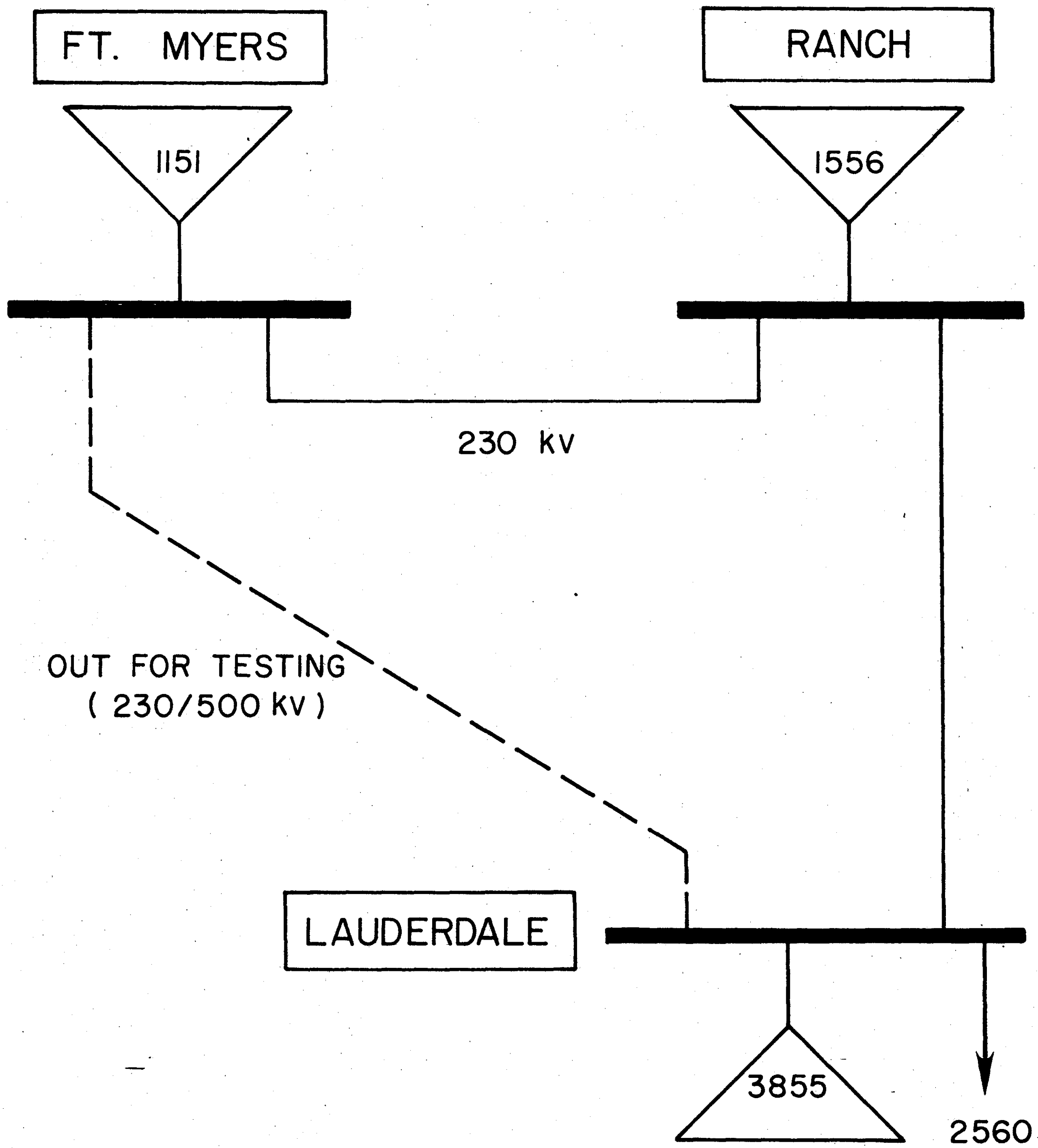
FT. MYERS
RANCH
1151
1556
230 KV
OUT FOR TESTING
(230/500 KV)
LAUDERDALE
3855
2560

FIGURE 3

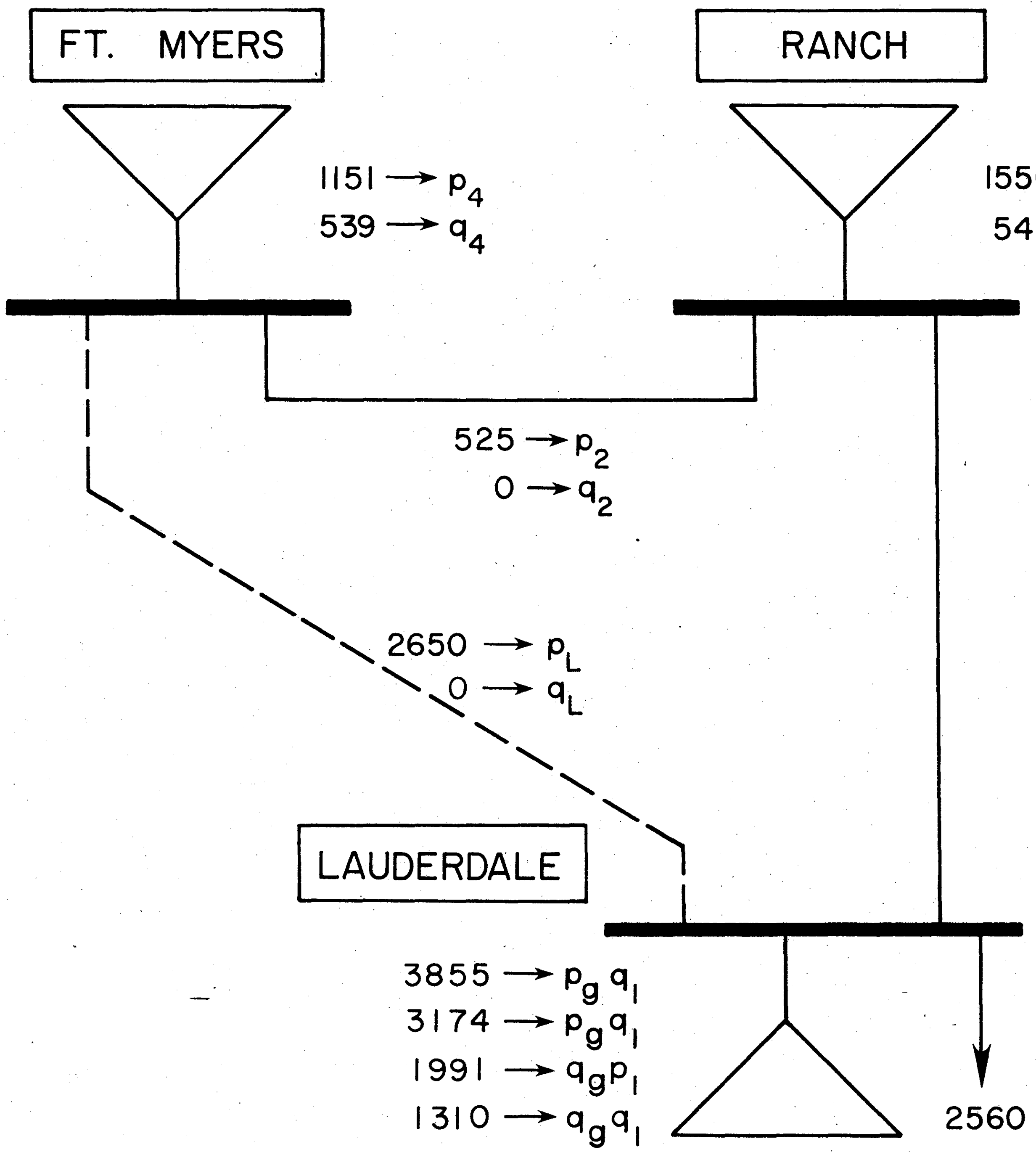
FT. MYERS
RANCH
1151 → p_4
539 → q_4
1556 → p_3
546 → q_3
525 → p_2
0 → q_2
2650 → p_L
0 → q_L
LAUDERDALE
3855 → $p_g\,q_1$
3174 → $p_g q_1$
1991 → $q_g p_1$
1310 → $q_g q_1$
2560

FIGURE 4

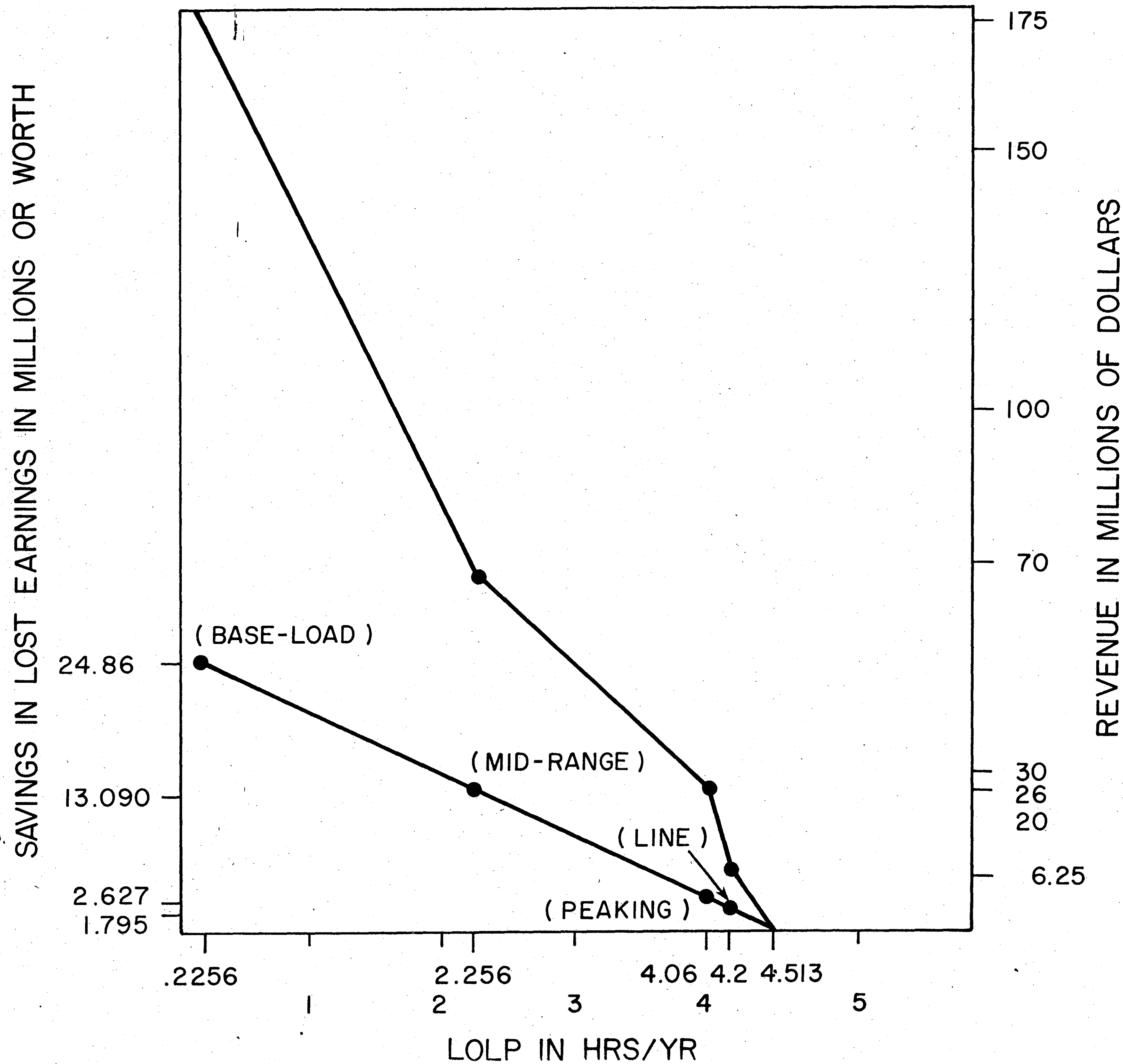
SAVINGS IN LOST EARNINGS IN MILLIONS OR WORTH
24.86
13.090
2.627
1.795
REVENUE IN MILLIONS OF DOLLARS
175
150
100
70
30
26
20
6.25
(BASE-LOAD)
(MID-RANGE)
(LINE)
(PEAKING)
.2256
2.256
4.06
4.2
4.513
1
2
3
4
5
LOLP IN HRS/YR

FIGURE 5

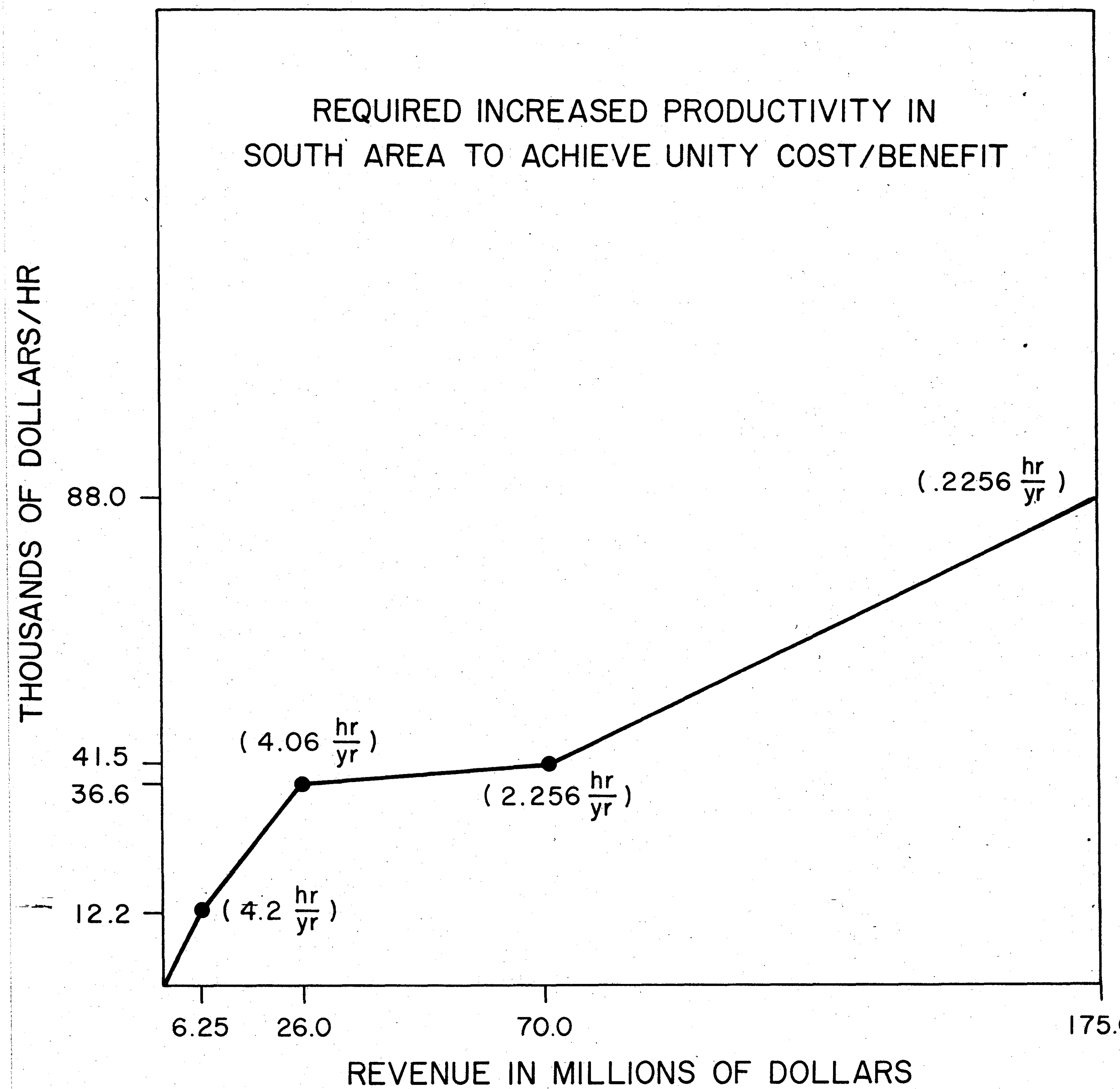
REQUIRED INCREASED PRODUCTIVITY IN
SOUTH AREA TO ACHIEVE UNITY COST/BENEFIT
THOUSANDS OF DOLLARS/HR
88.0
41.5
36.6
12.2
(.2256 hr/yr)
(4.06 hr/yr)
(2.256 hr/yr)
(4.2 hr/yr)
6.25
26.0
70.0
175.
REVENUE IN MILLIONS OF DOLLARS

FIGURE 6

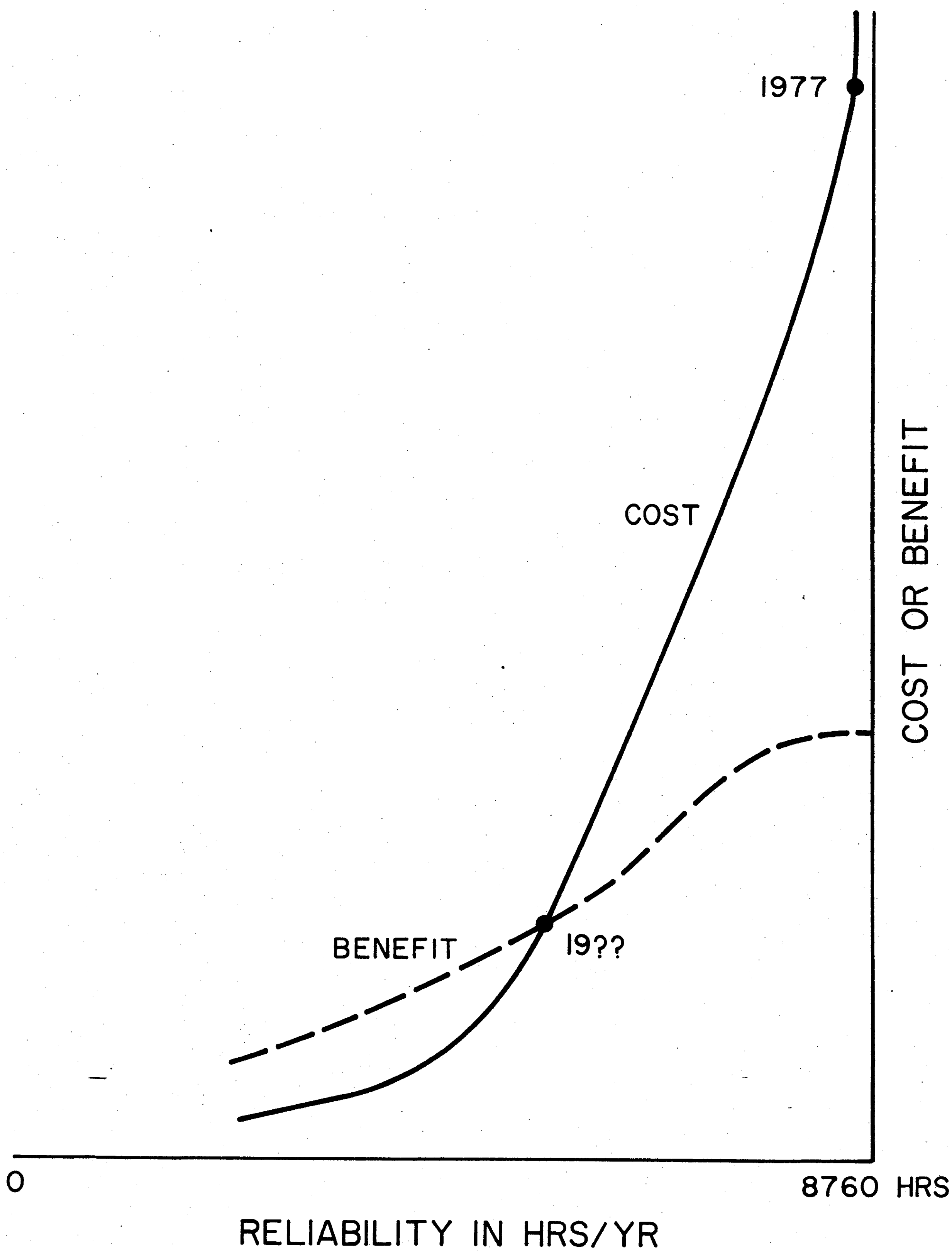
1977
COST
BENEFIT
19??
COST OR BENEFIT
0
8760 HRS
RELIABILITY IN HRS/YR

FIGURE 7

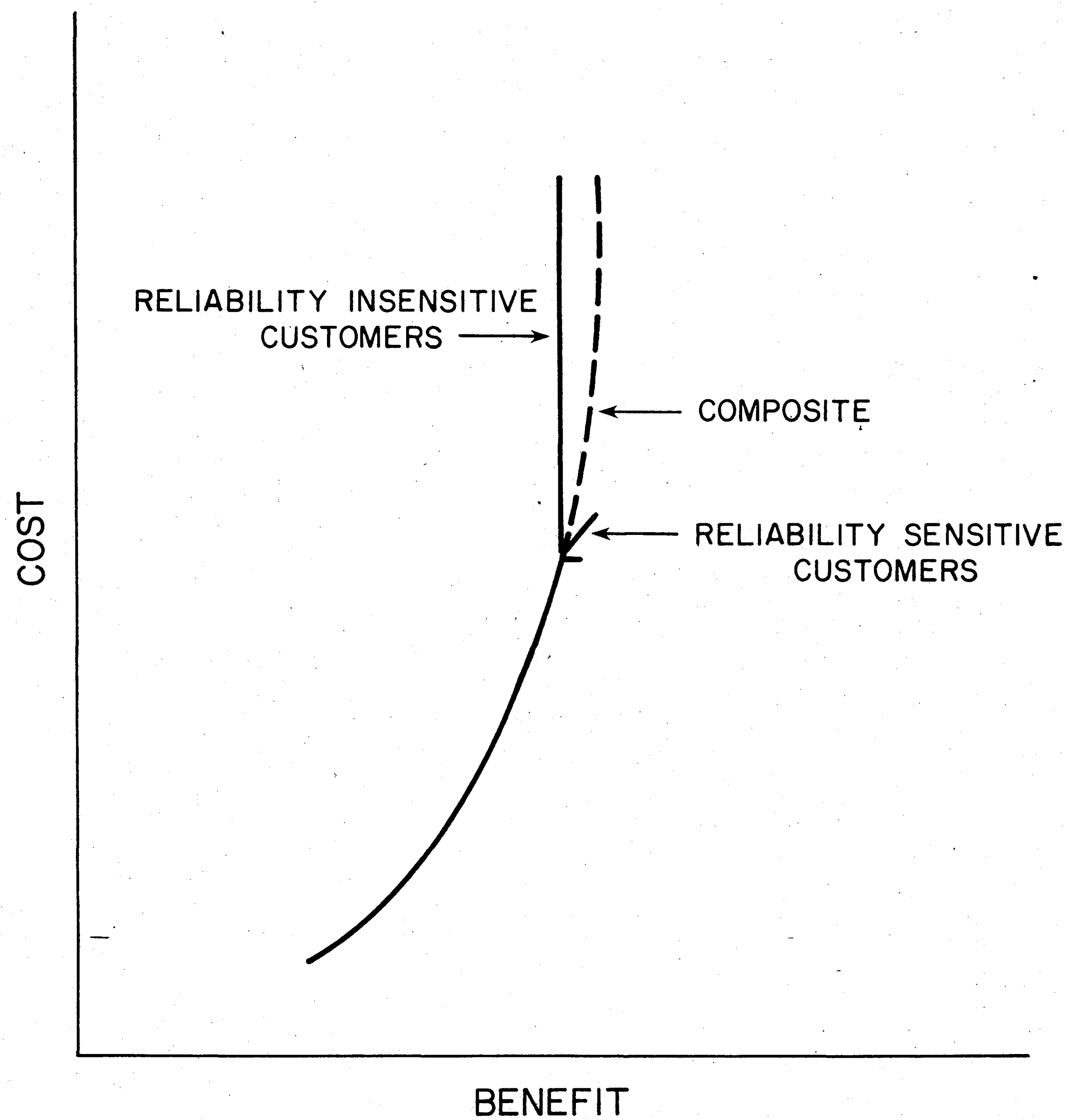
RELIABILITY INSENSITIVE
CUSTOMERS
COMPOSITE
RELIABILITY SENSITIVE
CUSTOMERS
COST
BENEFIT

FIGURE 8