Spare Transformers and More Frequent Replacement Increase Reliability, Decrease Cost

Charles D. Feinstein and Peter A. Morris

Satisfactory reliability and cost performance of transmission transformers is essential to the design and proper operation of the transmission grid. Transformers can be expensive to acquire (depending on the capacity and voltages involved), and the acquisition lead time is increasing (currently 15 months or more).

This article presents some results that suggest that transmission transformer inventories may not be presently managed optimally with respect to both life-cycle costs and risk of outage. In addition, although some transmission owners recognize that spares can be valuable in reducing life-cycle costs and risk of outage, neither the number of spares nor the location of existing spares on the transmission grid are optimal in many cases. In the studies we have performed, we have discovered opportunities for significant cost and risk reductions.

The main points of this article can be summarized as follows.

1. Transformer failure can be very expensive and ought to be avoided, but there is a cost trade-off.
2. The cost-effective way to mitigate risk of failure is twofold: (1) retire aging transformers and transformers that are known to be in poor condition and (2) add spares, depending on location and the cost of the consequences of outage.
3. The industry is not retiring transformers according to the least-cost policy. Therefore, the industry is running the transmission system at greater risk than is optimal in order to save replacement costs. The increased risk can be quantified and can be very large.
4. Spares can reduce risk in a very cost-effective manner. In particular, the availability of spares can increase the optimal retirement age. Total transformer asset management costs can be greatly reduced by the integration of spares into the system.
5. Spares can be optimally sited in the system to take advantage of geographic effects.
6. Even older transformers, each with a relatively small useful remaining life, can function as cost-effective spares.
7. All values provided by spares can be measured by a transparent methodology.

Before presenting the main results in some detail, it is appropriate to discuss the methodology that was applied to find the results. The methodology is found in the Appendix and should be reviewed before continuing with the article.

OPTIMAL RETIREMENT AGE

The optimal retirement age, given by the least-cost transformer management policy, varies with failure consequence cost. It should be intuitively clear that as the failure consequence cost increases, the best age at which to retire a transformer decreases.

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This is true because the condition-dependent hazard function is an increasing function of transformer age, so that as age increases, the likelihood of transformer failure increases; hence, the risk of outage increases. Further, as the transformer ages and experiences actual operations, its condition tends to worsen. As the condition worsens, the hazard increases. The hazard rate is the conditional probability that a transformer fails during the next interval of operating time, given that it has survived to the beginning of that interval. Thus, the hazard $h(t)$ is given by $h(t) = p\{t < L < t + dt \mid L > t\}$, where L denotes the random variable that is the lifetime of the transformer.

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A simple hazard function is given by the piecewise-linear hazard in **Exhibit 1**. The piecewise linear hazard has three parameters: *hss*, the steady-state hazard rate; T, the age at which the hazard begins to increase more rapidly (known as the time of onset of burnout); and m, the rate of burnout, which is the slope of the hazard rate after onset of burnout. The piecewise linear hazard is an approximation to other forms of hazard, such as the Weibull and the Perks' hazard,[1] given by the three-parameter function, $h(t) = \alpha e^{\beta t}/(1 + \mu e^{\beta t})$, which is the hazard function used in this study of transmission transformers.

The dependence of retirement age and failure consequence cost is shown in **Exhibit 2**. Note that the relationship is monotonically decreasing and relatively flat over a range of relatively large failure consequence costs. These costs are the costs of the consequences that would occur if there were loss of transformation for one year. Because the replacement time is now approximately 16 months, the risk of failure, with no spares, is governed by approximately four-thirds of this cost. With spares, the cost of a single outage is reduced because transformation can be restored within days (approximately 15 days if the spare is at the same location as the failed unit and approximately 60 days if the spare must be dispatched from some other location), not months. We will return to that idea below. Note that the policy indicates that if the failure consequence cost is approximately $50,000 a year, or about $1,000 a week, then the transformer should be replaced at approximately 30 years.

One should note that this is not a general recommendation. It happens that the optimal policy, given the parameters of the example shown, which include the consequence of outage costs, the hazard rates, the condition dynamics, and the discount rate, which surely vary by location and by asset owner, is to re-

Exhibit 1. Piecewise Linear Hazard Function

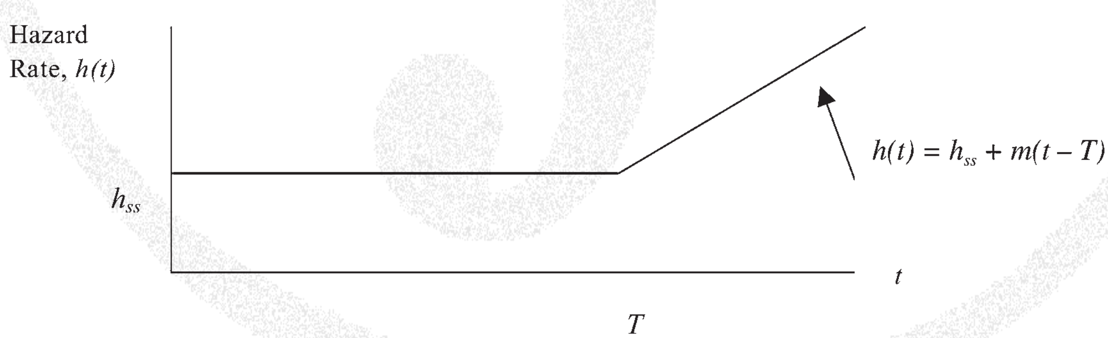
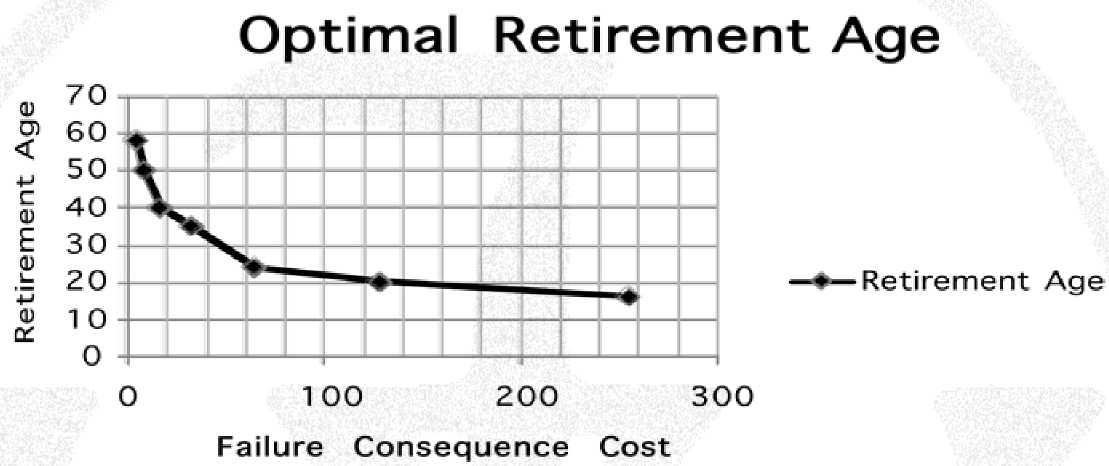


Exhibit 2. Sensitivity of the Optimal Retirement Age With Respect to Failure Consequence Cost



tire the transformer at approximately 30 years. There is no reason to believe that this is generally applicable. However, what is surely true is that there is some optimal retirement age, and the relationship of that age to the failure consequence cost is monotonically decreasing, as indicated in Exhibit 2.

…there is some optimal retirement age, and the relationship of that age to the failure consequence cost is monotonically decreasing…

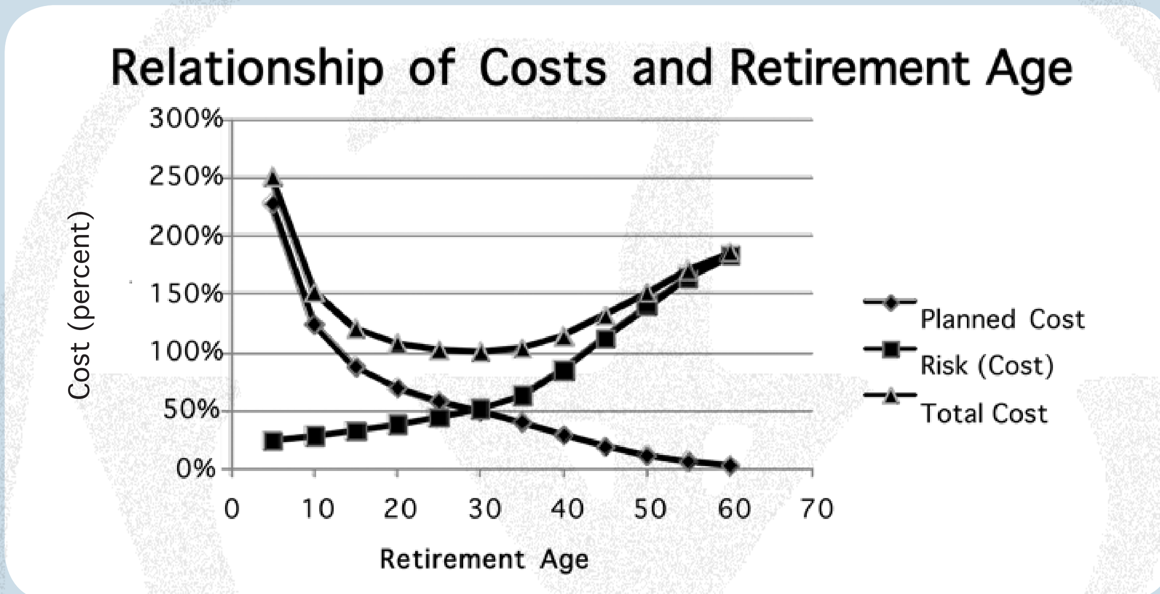
The intuitively clear notion that retirement age decreases with increasing outage cost can be supported with some further analysis. In particular, one may decompose the cost of any policy, optimal or not, into two components. Recall that the cost of a policy is the expected present value of the future cash flows associated with that policy.

The first component can be thought of as the direct management costs or planned costs, which include costs of replacement, repair, maintenance, and testing without any consequences of failure. These costs occur because of the requirements of the policy, especially the replacement costs for transformers that have not failed. These planned management costs decrease as the retirement age increases. Even though the costs of repair and maintenance tend to increase with transformer age, the present value of the capital replacement costs decreases because the retirement age increases, and that decrease dominates and determines the behavior of the planned costs. This is shown in **Exhibit 3** by the planned cost curve.

The second component of the optimal policy cost is the sum of the costs associated with the failure of transformers prior to replacement age. These costs can be thought of as the unplanned costs or risk of outage costs or, as noted in Exhibit 3, the risk (cost). Because the hazard rate increases as the transformer ages, the risk of outage costs are an increasing function of the replacement interval. Hence, the total policy cost is the sum of the planned and unplanned, or risk, costs.

The optimal retirement age occurs at the minimum of this sum. This is achieved at 30 years, as shown in Exhibit 3. (Note that it is a common misconception that the sum of an increasing function and a decreasing function achieves its minimum at the point of intersection of the two functions. This is generally false, but true in one special case [the familiar EOQ inventory model] that has been incorrectly taken to be universal. The

Exhibit 3. Decomposition of the Total Cost Into Planned Cost and Risk of Outage Cost, as a Function of Retirement Age



minimum occurs at the point at which the first derivatives are equal in absolute value but opposite in sign. In the example in Exhibit 3, the planned cost and the risk [cost] are close but not equal at retirement age 30 years.)

Thus, Exhibit 3 presents three cost curves. The top curve is the u-shaped total cost curve, which is minimized at retirement age 30 years. The value of this minimum is scaled to 100 percent. The monotonically decreasing curve is the direct cost curve. At retirement age 30 years, its scaled value is approximately 50 percent. The monotonically increasing curve is the risk of outage costs, denoted risk (cost). It is also approximately 50 percent in scaled value at retirement age 30 years. The sum of these two scaled values is the minimum value of the total cost curve, or 100 percent.

Now, consider the effect of increasing the failure consequence cost. As noted above, the optimal retirement age decreases (recall Exhibit 2). The cost decomposition analysis indicates this as well. The planned costs are unchanged because they do not include the consequences of transformer failure. The risk-of-outage costs (the unplanned costs) uniformly increase, with increasing first derivative. Hence, the minimum of the sum must shift to the left, which means that the optimal replacement age decreases as outage costs increase. This is shown in **Exhibit 4**, which indicates that the optimal retirement age is between 20 and 25 years, where the total cost curve is relatively flat.

Notice that increasing the failure consequence cost (doubled in this example) caused the risk (cost) curve to move upward and to the left in the graph and the optimal retirement age therefore decreased.

INCREASING RETIREMENT AGE AND INCREASING OPERATING RISK

A further conclusion can be drawn from this decomposition of costs. What the industry appears to be doing is keeping transmission transformers in service beyond the optimal replacement age. In the example treated in the exhibits, the failure consequence cost is approximately $50,000 a year, and the optimal replacement age is 30 years.

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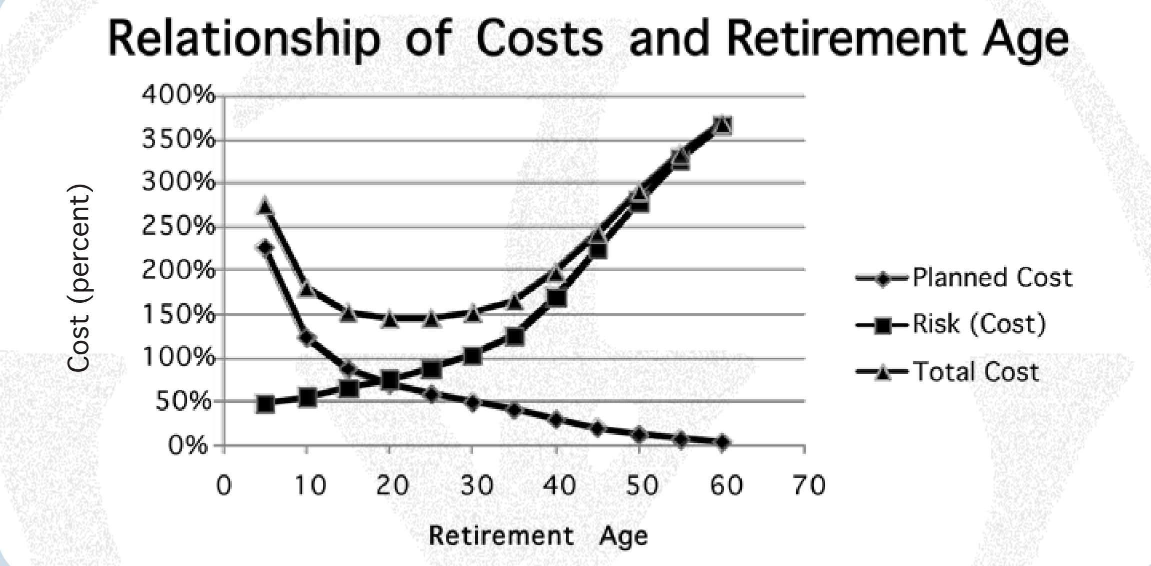
Exhibit 4. Effect of Increasing Failure Consequence Cost on Risk (Cost) and Therefore the Optimal Retirement Age



Suppose that the actual policy is to retire transformers at 60 years. The decrease in planned cost achieved by this policy is the real and large benefit of nearly 50 percent of the optimal total cost, as indicated in **Exhibit 5**. However, there is an accompanying increase in the risky or unplanned costs.

This latter increase is also large and greater than the decrease in planned costs, which merely restates the fact that replacing at 30 years is optimal and replacing at 60 years is not. Further, the risk (cost) level that was at 50 percent of the optimal total cost has now increased to approximately 180 percent of the optimal total cost. Thus, retiring at 60 years has increased the total cost by 85 percent, going from 100 percent to approximately 185 percent, and the operating risk has more than tripled, going from 50 percent to 180 percent in relative terms. This is shown in Exhibit 5.

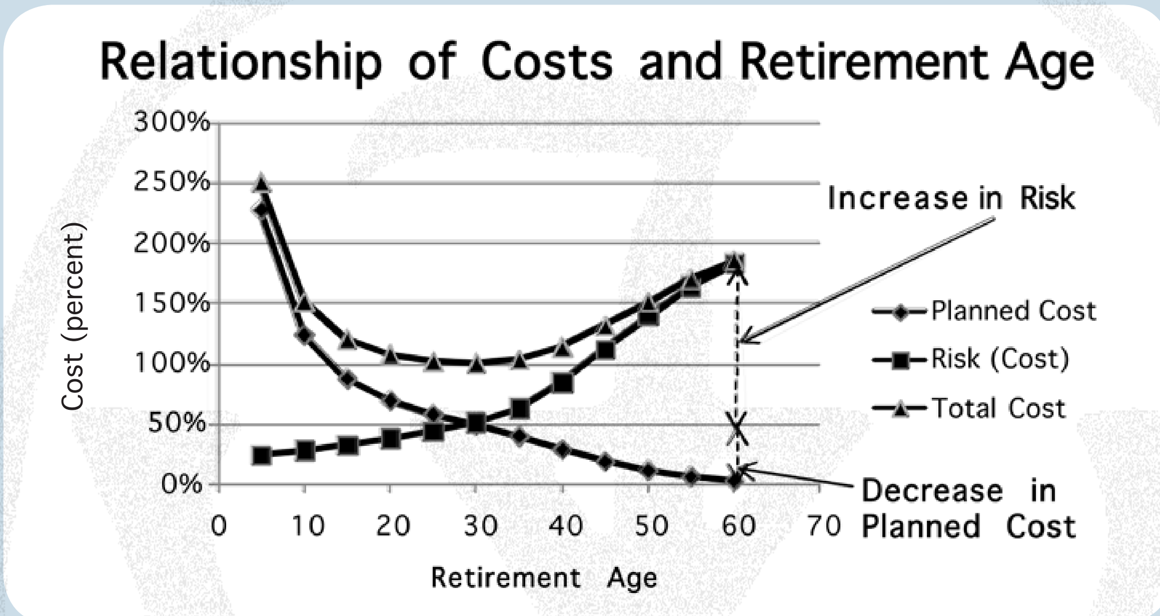
In other words, in order to achieve the real benefit of reduction in the planned or direct operating cost, the transmission system is exposed to an increased amount of risk. Notice that these estimates of increased risk are based only on the change in expected value of outage costs. The variance of those costs has increased as well, although that is not shown in the exhibit. This analysis suggests that transmission owners that are operating beyond the optimal replacement age may not be properly accounting for risk, or, they are willing to accept the additional risk even though an expected value analysis suggests that it is not cost-effective to do so. Either way, the transmission system appears to be operated at an elevated level of risk with no expected benefit.

THE EFFECT OF SPARES ON OPTIMAL RETIREMENT AGE

If a spare is present at a transmission transformer location and if a transformer failure occurs (the probability of which is given by the condition-dependent hazard rate), then the consequences of that failure are reduced. That is, the days during which transmission does not occur are reduced from the current acquisition lead time, approximately 16 months, to the time required to connect the spare, which can be as little as 15 days.

This reduces the failure consequence cost of a transformer failure. Hence, the optimal

Exhibit 5. Increase in Risk and Total Cost if Transformers Are Retired Later Than Optimal



retirement age with a spare can increase compared with the optimal retirement age with no spares present because the increase in the hazard rate for older transformers combines with the decrease in failure consequence cost provided by the spare to achieve a similar level of outage risk in both cases. Further, because increasing the retirement age decreases the planned or direct operation costs, as shown in Exhibit 5, the optimal level of risk, measured by the unplanned cost, can increase somewhat compared with the level of risk or unplanned cost achieved in the optimal solution with no spares. In other words, the presence of spares allows the transmission system to be operated in what appears to be a more risky manner, which is defensible and cost-justified.

…the optimal retirement age with a spare can increase compared with the optimal retirement age with no spares present…

Exhibit 6 extends Exhibit 2 and presents the effect of spares on the optimal retirement age. There are two spare scenarios shown in the exhibit. A replacement spare is a spare that is created, so to speak, when a transformer is retired according to the optimal retirement policy. The average age of spares in steady state is approximately 50 percent greater than the optimal retirement age.

A renewal spare is a spare that is acquired when a transformer is replaced or fails.

A renewal spare is a spare that is acquired when a transformer is replaced or fails. This policy is surely extremely redundant, but it provides a limit on the effect of spares on retirement age. The average age of spares in the renewal scenario is one-half the optimal retirement age. Both the replacement and renewal policies indicate that the optimal retirement age increases compared with the policy with no spares.

VALUE OF SPARES

The value of a spare at a location depends on the ages and conditions of the transformers at that location, the failure consequence cost at that location, the transformer acquisition

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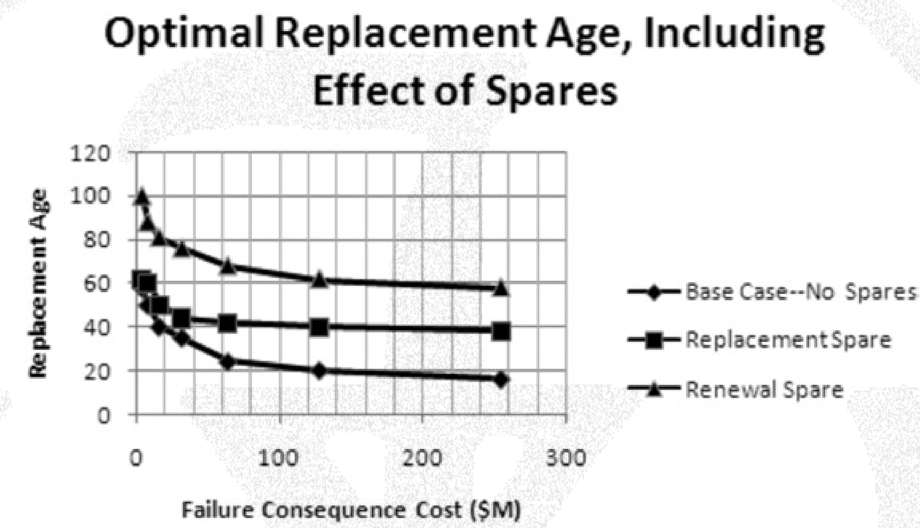
Exhibit 6. Effect of Spares on Transformer Retirement Age



lead time for the location, and the time to restore transmission if the spare is locally sited. In addition, the spare has value if it can be dispatched to another location in the transmission system. Transmission owners may have assets at different locations that can be served by a single spare. Further, transmission owners may be in a regional group such that a single spare can be dispatched to any location in the group.

In addition, the spare has value if it can be dispatched to another location in the transmission system.

The location value of a spare also depends on the number of failed units at the location. For example, if two units are required for transformation at a location, then a single spare will be unable to provide transformation if two units have failed. Hence, the value of a spare depends on the probability distribution on the number of units that have failed.

That probability distribution depends on the applicable hazard rates, as well as such considerations as common mode failures due to vintage and manufacturer, external events such as the arrival of hurricanes and tornadoes, and locational dependencies such as single-phase unit cascading failures and bank-to-bank dependencies. (The main idea here is that single failure can trigger dependent, sometimes catastrophic, failures. A special purpose mathematical model of dependent failures was created to capture this phenomenon.) The methodology used to compute the probability distribution on the number of failed units considers all these effects.

Exhibit 7 presents the value of spares at a collection of locations in a single group that can be supported by a dispatchable spare. The values were found by the methodology briefly described above. The values in the table, which is an output of the methodology, measure the amount of expected outage cost that can be avoided by a spare.

Note that the values of a spare at a location can be placed in sequence of decreasing value. The most valuable spare is at Three Corners and is worth $6,664 a year. The next most valuable is at Dexter and is worth $6,500 a year. The Optimal Sequence row displays these values in decreasing order. These are

Exhibit 7. Value of Spares at Locations Within a Group

SPARES GROUP	ALL	EXISTING SPARES INCLUDED IN ANALYSIS
1 OR 3 PHASE	3	

	Incremental Spare Value ($ Millions)										
Location	0	1	2	3	4	5	6	7	8	9	10
Dexter	0.000	6.500	0.265	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
East Williamsburg	0.000	0.457	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Lawrence	0.000	0.587	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Milton	0.000	0.911	0.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Three Corners	0.000	6.664	0.220	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Optimal Sequence	0.000	6.664	6.500	0.911	0.587	0.457	0.265	0.220	0.006	0.000	0.000
Entire Spares Group	0.000	12.687	1.566	0.112	0.005	0.000	0.000	0.000	0.000	0.000	0.000

location-specific spare values. Now suppose that a spare at any location can be dispatched to any other location in the group, which would entail a longer time to restore service (60 days for a remote spare compared with 15 days for a local spare). Therefore, a revised sequence of values applies and is shown the Entire Spares Group row. The most valuable spare is worth $12,687, which follows from the fact that the single spare can cover the entire set of locations. The value of the second spare is an order of magnitude less, $1,566, which follows because the likelihood of two failures among the set of five locations is relatively small.

…the values of a spare at a location can be placed in sequence of decreasing value.

Further, a spare can be cost-justified based on its capital cost ($4,000 in this example), the discount rate (5 percent a year), and the payback period (12 years), which, in this example, is approximately $450 a year. Hence, five location-specific spares can be cost-justified, with a total expected risk reduction of $15,119 a year. Alternatively, only two group spares can be cost-justified, and they provide a total expected risk reduction of $14,253 a year. Thus, the group spares provide a bit more than 94 percent of the risk reduction at 40 percent of the cost, compared with local spares.

AGE-DEPENDENT VALUE OF SPARES

One of the very interesting results of the spares analysis is that old spares, which may be deemed of little value as primary operating transformers, can provide a great deal of value to the system. **Exhibit 8**, an output of the methodology, compares the costs of several cases. The Cost column is the expected present value of the optimal policy with spares and age- and condition-dependent retirement. The RTF Cost is the policy cost that results if the transformers are always run to failure and never retired, but merely replaced.

The cost of the run-to-failure policy is approximately triple the cost of the optimal policy.

The table presents a case in which the optimal retirement age is 15 years when there are no spares. The cost of the run-to-failure policy is approximately triple the cost of the optimal policy. This is shown in the first row of Exhibit 8. One might ask whether a spare of a given age could cost-effectively double that retirement age. The table indicates that a spare that is 55 years old, on average, will permit the transformer to remain in service

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Exhibit 8. Effect of the Age of Spares on Retirement Policy Specification and Cost

Spares	Spare Age	Retirement Age	Cost	RTF Cost
0		15	72.9	216.3
1	55	30	20.7	63.0
1	35	40	13.2	38.7
2	65	40	11.1	31.8

until it reaches 30 years. The cost of that optimal policy is approximately 30 percent of the original cost.

Similarly, the cost of the run-to-failure policy also decreases by approximately 70 percent. This is shown in the second row of Exhibit 8. Following essentially the renewal spare logic, the table presents a case when the spare age is 35 years on average. The optimal retirement age has now increased to 40 years, but the cost of the optimal policy has decreased further, to less than 20 percent of the original cost. The cost of the run-to-failure policy with this spare has also decreased, but it is, of course, greater than the optimal policy cost, by the persistent factor of three.

The cost of the run-to-failure policy with this spare has also decreased, but it is, of course, greater than the optimal policy cost, by the persistent factor of three.

Finally, the last row of the table presents the effect of having two relatively old spares (65 years) to support the transformer. In the case shown, the retirement age remains the same (40 years), but the cost decreases by an additional 15 percent compared with the renewal spare case. Therefore, the table suggests that the optimal solution is the fourth row, with a cost savings of about 85 percent compared to the optimal policy with no spares.

Perhaps a useful analogy is provided by spare tires in passenger automobiles. We all drive around with a spare in the trunk. But if a road service, say Triple-T (Tires, tires, tires), could dispatch a spare in very little time, then we would not pay the additional 25 percent of the tire capital charge to carry our own. Moreover, the Triple-T tire need not be a very good one because all we need is to get to a location that could put a good tire on for us in a reasonable, manageable time.

We all drive around with a spare in the trunk. But if a road service, say Triple-T (Tires, tires, tires), could dispatch a spare in very little time, then we would not pay the additional 25 percent of the tire capital charge to carry our own.

Alternatively, if we had the trunk space and did not care to rely on Triple-T, we might be well advised to keep two old tires around rather than pay for a new one that we are very unlikely to use. Of course, that implies that one is willing to undertake the labor and accept the time required to change the tire, should the event occur.

It appears that the transmission system is currently being operated at substantially greater risk than is optimal.

CONCLUSIONS

It appears that the transmission system is currently being operated at substantially greater risk than is optimal. The real reduction in transformer replacement costs (planned costs) that occurs because transformers are operated beyond their optimal retirement age is not justified because the increased risk of outages, measured by the unplanned costs, exceeds the reduction in planned costs.

Spares can be introduced into the transmission system at specific locations in order to reduce the unplanned or risky cost. When spares are introduced, the optimal retirement age increases, the system can be justifiably operated at greater likelihood of a single transformer failure, and the overall operating cost (planned plus unplanned) is reduced. These results have been found by two repeatable methodologies that determine the optimal replacement policy and the value of spares in the transmission system.

NOTE

1. Egan, D. M., & Chen, Q. (2006, November). A Bayesian method for transformer life estimation using Perks' hazard function. *IEEE Transactions on Power Systems*, 21, 1954–1965.

Appendix. Methodology

Managing transmission transformers is an example of the class of asset management problems that have been addressed by a formal, repeatable, transparent analytic methodology that has been applied to several similar asset populations, including underground cable, wood poles, breakers, and transformers, both distribution and transmission.[1] The methodology as well as the current application, to transmission transformers and spares, has been presented at the Institute of Electrical and Electronic Engineers (IEEE) and Electric Power Research Institute (EPRI) conferences.[2]

The management problem is formulated as an optimal control problem over an infinite horizon with the following essential aspects. The policy question is what to do with an asset (replace, repair, maintain, test, do nothing), and when (age) and under what circumstances (asset condition, test result) to do it. The methodology identifies the optimal policy over the infinite horizon. The objective of the policy is to minimize the life-cycle cost of managing the inventory (i.e., minimize the expected present value of the future cash flows associated with the management policy).

The key risk is the risk of outage. Outage is caused by transformer failure. The probability that a transformer fails is governed by a condition-dependent hazard function. Thus, if the condition of the transformer and its age are known, then the probability that it fails in any given year is provided by the condition-dependent hazard function. The hazard function can be found empirically from either survival data or life distribution data.[3]

The consequences of loss of transmission are measured by the sum of applicable costs including congestion cost, collateral and environmental costs, and litigation costs, as well as the replacement cost of the failed unit. These costs vary geographically. Therefore, the outage risk is based on the joint behavior of the hazard rate and the failure consequence cost.

What makes the problem an optimal control problem is the fact that the condition of the transformer, an essentially unobservable variable, changes over time and can be controlled to some degree and observed to some degree. The condition is modeled as a discrete, uncertain variable, governed by a dynamic probabilistic system. The probability distribution of the condition can be modified by management actions (replace, repair, maintain) and can be inferred from test outcomes.

Therefore, if the probability distribution of the condition is known and the condition-dependent hazard rates are known, then the unconditional hazard rate is known, which, in combination with the applicable failure consequence cost, specifies the risk of operating the transformer over the next period. This risk can be compared with the costs and benefits of management action, and the optimal dynamic policy can therefore be found. This is what the methodology determines.

NOTES

1. See the following papers by Feinstein, C. D., & Morris, P. A. (2003). *Cable reliability management strategies. EPRI publication 1002257.* (2006). *Guidelines for intelligent asset replacement, Volume 4—Wood poles* (Expanded Edition). EPRI publication 1012500. (2003). *Guidelines for intelligent asset replacement, Volume 1.* EPRI publication 1002086. (2006). *Substation transformer asset management and testing methodology.* EPRI publication 1012505. Palo Alto, CA: Electric Power Research Institute.

2. Feinstein, C. D., & Morris, P. A. (2007, June). *Optimal management of aging assets in electric utility systems: Lifecycle costs and repair/replace strategies including the effect of spares.* Tampa, FL: IEEE Power Engineering Society; and Bloom, J., Feinstein, C. D., & Morris, P. A. (2006, October). *Optimal replacement of underground distribution cables.* Atlanta, GA: IEEE Power Engineering Society.

3. Egan, D. M., & Chen, Q. (2006, November). A Bayesian method for transformer life estimation using Perk's hazard function. *IEEE Transactions on Power Systems,* 21, 1954–1965; Feinstein, C. D., & Morris, P. A. (2003). *Medium voltage cable failure trends.* EPRI publication 1002256. Palo Alto, CA: Electric Power Research Institute; Feinstein, C. D., & Morris, P. A. (2006). *Equipment failure model and data for substation transformers.* EPRI publication 1012503. Palo Alto, CA: Electric Power Research Institute.

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