Cost optimization in mechanical seal applications

Real-life case studies prove it is possible to make more informed choices that often lead to cost savings

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Considerable cost reductions are possible in mechanical seals and associated systems once influencing factors are understood and taken into account. As with other machinery-related topics and issues, it is important to:

- Know the various design options and their respective advantages, disadvantage and limitations. These details are usually (but not always) available from seal vendors.
- Verify the above details. They should be furnished by seal vendors and must be based on end-user application experience from other industries or facilities.
- Have knowledge of complete pumpage property, utilities available, flare pressure and process variation. The possibility of operational upsets associated process requirements should be addressed as well.
- Closely interact with maintenance and plant operators from one's own plant. Essentially, there needs to be an awareness of prevailing operating and maintenance philosophies.
- Accept the inherent limitations of industry standards. Standards will take a conservative approach and are generic.[1] This means that following through with thoughtful and judicious selection processes may allow bypassing certain stipulations. Safely bypassing these stipulations is often possible in niche applications and will achieve cost savings.

Several implementations based on the above approach have led to cost savings; they are described below and may help the cost-conscious end user to make a more suitable choice. The typical cost elements and calculations for life-cycle cost (LCC) for a five-year equipment life are given in Table 1.

It should be noted that cost calculations will differ for each particular case since contributing elements cover a wide range from plant to plant and also from country to country. Among the important variables we find are: initial equipment cost, labor and utilities. Of special concern here is cooling water—unfortunately considered negligible in India—and the maintenance and other cost contributions related to environmental safety standards.

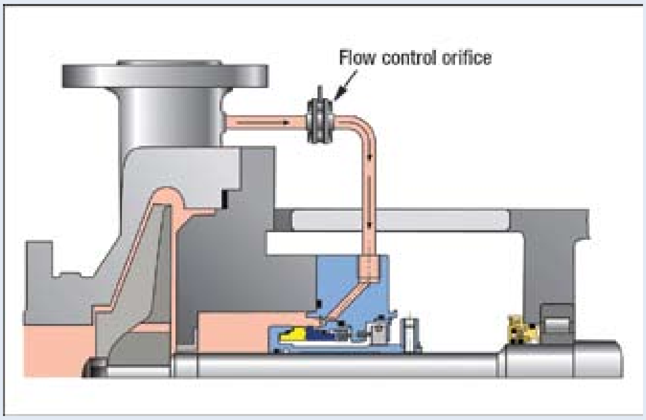
Accordingly, and although LCC calculations are mentioned, cost reductions also relate to such seemingly intangible benefits as discontinuing water cooling, savings in extra instrumentation and auxiliaries, and the value of uptime extensions. It might even be reasoned that these intangibles are more important in LCC calculations than in initial equipment cost.

Virtually all mechanical seals require separating the rotating seal face from the stationary face. A liquid is generally best suited to provide both face separation and cooling. The American Petroleum Institute (API) has long recognized this fact and facilitated our understanding by issuing relevant standards for our general guidance. These standards represent users, and manufacturers, collective experience; the API seal plans or flush plans published in applicable documents such as API-682[2] facilitate communicating seal-related knowledge.

API Plan 11 (Fig. 1) is one of the most common flush recommendations we find in these specifications. As is the case with all other plans, it is intended for use in a certain operating range and, as can be expected, has limitations when operated outside this range. Some case studies highlight the particulars.

Case 1: API Plan 11 or Plan 23? For hot water or condensate applications above 80°C, end users generally opt for single mechanical seals with Plans 21 (Fig. 2) or 23 (Fig. 3). These flush plans provide a cool flush to the seal; also, at least one tutorial on plan selection mentions Plan 23 as the standard selection for such applications.[2]

Hot water has very low lubricity above 80°C, resulting in high seal face wear that generally makes Plan 23 requirement a very prudent selection.



API Plan 11 and injecting a controlled pumpage flow (a side stream taken from a higher pressure source) into the seal environment.

TABLE 1. Life cycle cost in Indian Rs. (US $)

Input:[5] costs in Indian Rs.	1 Mech. seal + Plan 23	2 Mech. seal + Plan 11	3 Mech. seal + Plan 75	4 Mech. seal + Plan 52 (b)	5 Plan M (c)
Initial investment cost (a)	285,000	250,000	495,000	690,000	200,000
Installation and commissioning cost	6,600	0	6,600	6,600	6,600
Energy price (present) per kWh	4	4	4	4	4
Weighted average power of equipment in kW (d)	1.83	1.6	0.48	1.1675	0.1875
Average operating hours/year	8,000	8,000	8,000	8,000	8,000
Energy cost/year (calculated) = energy price x weighted average power x average operating hours/year	58,560	51,200	15,360	28,160	6,000
Operating cost/year	5,000	5,000	5,000	5,000	5,000
Maintenance cost (routine maintenance/year)	4,500	900	6,300	6,300	4,500
Repair cost every 2nd year (e)	60,000	75,000	75,000	60,000	0
Other yearly costs (f)	1,300	0	10,500	34,300	1,300
Downtime cost/year	0	0	0	0	0
Environmental cost	0	0	2,000	2,000	0
Decommissioning/disposal cost	500	0	500	500	500
n—Life in years	5	5	5	5	5
i—interest rate, %	10	10	10	10	10
p—Inflation rate, %	6	6	6	6	6
Output: net present LCC value (g)	710,000 (US $16,000)	640,000 (US $14,200)	800,000 (US $17,800)	1,177,814 (US $26,174)	117,000 (US $2,600)

a) Mechanical seal cost (if applicable) + cooler (if applicable) + piping and auxiliaries.
b) Plan 52 cost includes the seal heat-exchanger cooling Plan M cost as per Reference 9.
c) Plan M seal cooling cost estimation is as per schematics given in Reference 9.
d) Energy consumed by mechanical seal cost + recirculation liquid energy cost applicable for Plan 11 only + cooling-water cost.
e) Repair cost of mechanical seal.
f) Cooler repair and cleaning costs + instrument calibration and repair + buffer/barrier liquid replacement.
g) 1 US$ = Indian Rs. 45.

Authors' notes:
*Investment costs appear to have been calculated based on hardware considerations. The user should be mindful of the piping connection and instrument hookup costs.
*Plan 75 is normally the most expensive since it requires connection to the flare and close drain systems. Plans 76 and 52 require connection to flare.

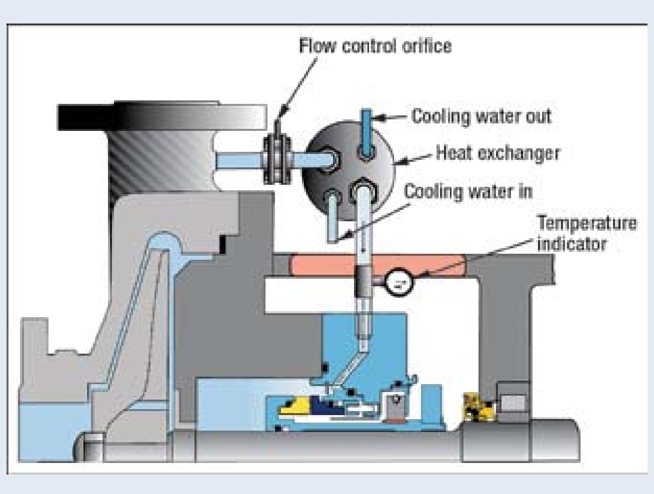


FIG. 2 API Plan 21—Product recirculation from discharge through flow control orifice and heat exchanger to seal chamber.

However, a specially designed seal with face-enhancing features outlined in API-682 may allow the user to stay with Plan 11. Usually the pressure distribution across the conventional seal faces is linear and drops from sealing box pressure at the outer seal face diameter to atmospheric pressure at the inner diameter. Depending on pressure and temperature, vaporization may take place part-way across the seal face. Designs with features that might include a water groove or an engineered laser etching are aimed at deferring or even avoiding this vaporization.

Although these specially designed seals have limitations and are influenced by stuffing-box pressure, pumpage temperature and peripheral speed, they cover many of the applications in hot-water services with Plan 11 instead of Plans 21 or 23. Use of Plan 11 over Plan 21 or 23 allows eliminating the cooling system. (The advantages of cooling device elimination are described in references 3 and 4).

The initial bare seal cost of a specially designed water groove seal is usually 10% to 20% higher than a conventional API-682 seal requiring Plans 21 or 23. Eliminating the cooler and piping, however, reduces the overall initial investment (refer to columns 1 and 2, Table 1).

The typical cost elements for special seals with Plan 11 and conventional seals with Plan 23 for a boiler feedwater pump (300 m^3/h at 243-m head and 120°C) are given in Table 1. In each instance, the seals are for a 3.625-in. shaft size and in general compliance with the guidelines found in reference 2.

The LCC for both options was calculated per reference 5 and is shown in columns 1 and 2 of Table 1. A five-year life span, a 10% interest rate and a 6% inflation rate were applied. The slight economic advantage of seals requiring Plan 11 is evident; however, eliminating cooling-water requirements should be factored in when the user decides on a preference.

Case 2: Plan 21 vs. Plan 23. As a general rule, Plan 23 is considered a better option than Plan 21; some inherent advantages are spelled out in reference 2. Among these, Plan 23 has a lower heat load that allows using a smaller cooler or an extended cooler life. Plan 21 consumes more energy than Plan 23 because the pumped fluid must first be cooled and then repumped from suction back to discharge. There is also a heat load addition due to the cooling requirements. To avoid undersizing, cooler load calculations must be done carefully for Plan 21.

While Plan 23 would thus seem to be favored, some site experiences may prove different. In this particular case history, seal units supplied with Plan 23 were later modified to Plan 21. The negative experience with Plan 23 was attributed to the following:

- Hydraulic friction losses in the piping connected to the pumping element are available with respect to water and inadvertently used for pumpage other than water. The pipe friction losses, calculated based on water as the medium, will often prove incorrect for liquids such as LNG or lube oil. To not misjudge the effectiveness of a particular pumping element, the system resistance calculation must reflect pumpage actually handled.
- The capability needed by a pumping element to overcome system resistance was not checked by either the pump or seal supplier. The pumping element *H-Q* characteristics should comply with clause 8.6.2.2 of API-862 (Reference 2) and piping friction and heat loss calculations must be accurate.
- The pumping element proved ineffective due to vapor-lock, wrong location of inlet/outlet ports, and changes in fluid properties, poor design and reduced operating speed. Speed changes are possible in case of pumps fitted with a variable-speed drive or when an existing drive is replaced with a lower-speed version.
- Pumpage properties such as solids content, suction and stuffing-box pressure margin over vapor pressure and the pumpage tendency to solidify were not taken into account at the time of plan selection.
- The available pumping element—in this case, an elementary pumping ring—proved ineffective. A better option might have been a pumping screw[6] or an innovative bidirectional pumping ring.[7] The latter is certainly also the most reliable. Pumping screws are efficient but require close gaps that cause their own set of concerns in case of shaft deflection and internal rubbing. Moreover, the unidirectional pumping screw geometry can create interchangeability problems.

Poor Plan 23 execution is often at fault and needs to be corrected before concluding that Plan 21 excels. Heat loads imposed on cooling towers in many plants can be a major issue along with cooler fouling. Heat removed at the seal is heat removed from the process. Heat allowed to return into the process represents an inefficiency that often reaches 10 kW or more—an amount that simply cannot be ignored.

In short, careful piping system analysis is needed if selecting Plan 23. The responsible engineer must ensure that the needed flush flowrate is, in fact, achieved at the anticipated operating speed. Seal accessories such as piping, instrumentation, reservoir and coolers should preferably be procured from the seal manufacturer. This will facilitate verifying actual recirculation flows and ascertain pumping device efficiency. If needed, the coordinating corrective measures will be greatly simplified. Suction pressure fluctuations are to be taken into account, since this can lead to inadequate margin over vapor pressure—a frequently overlooked issue resulting in vapor-lock even with venting holes.

The most practical option for an end user or equipment owner may well be Plan 23, if all parameters favor it. Select Plan 21 if the data for LCC calculations and technical support are lacking, in which case, you might not be able to verify the full adequacy of Plan 23. At all times, question the seal vendor and do not take anything for granted. Just because it might be tradition among seal vendors to do such-and-such doesn't necessarily make it the most intelligent choice.

Case 3: Instrumentation for Plans 52/53A/75. Costly instruments can be avoided if pumpage vapor and flare pressure variations are given due consideration. In a particular case where Plan 75 (Fig. 4) had been supplied, an operations department felt compelled to check if the sealing system could be operated without a high-pressure switch (PSH). In general, Plan 75 is suitable for condensing leakage. Reference 2 and other industry guidelines clearly mention that the PSH is expected to operate if leakage is vapor and if the amount is judged excessive. In this instance, the operations department confirmed that the vapor pressure would

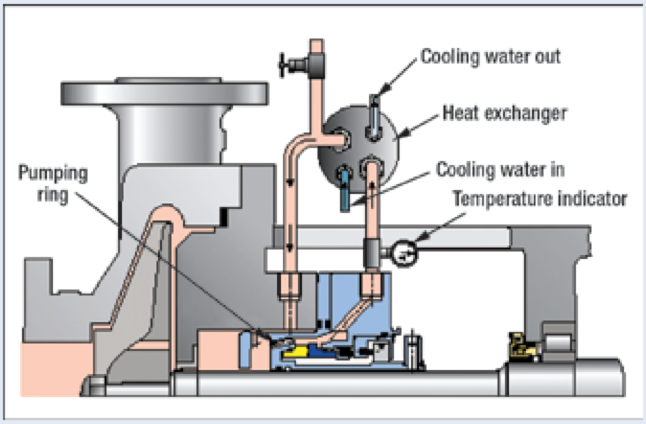


FIG. 3 API Plan 23—Product recirculation from seal chamber to heat exchanger and back to seal chamber. A bidirectional pumping ring and advanced-style bearing protector seal are shown in this illustration.

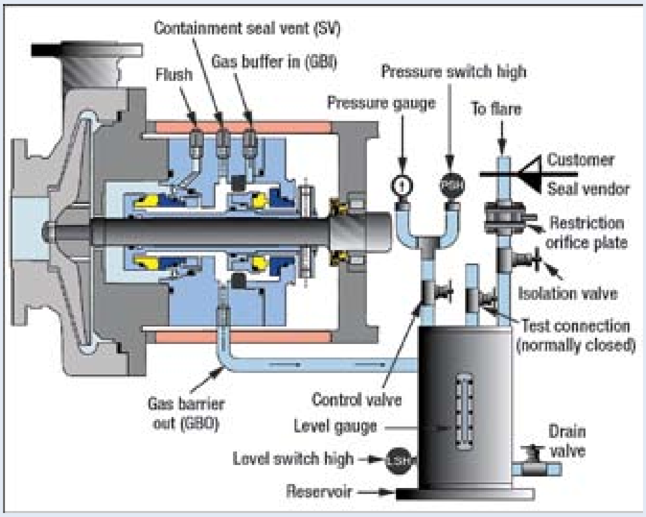


FIG. 4 API Plan 75—Process liquid leakage from the inboard section of a dual-containment seal is sent to a liquid collector.

TABLE 2. Guidelines for pressure and level switches selections for Plans 52/53A/75 (Case 2)

Plan	Pumpage vapor pressure	Pressure switch High	Pressure switch Low	Level switch High	Level switch Low	Technical justification for recommendation
52	> or < flare pressure	R	–	R	R	In this situation, since the flare pressure normally keeps on varying, all media that have a vapor pressure > or < flare pressure may leak to the outboard area in vapor or liquid forms depending upon the flare pressure at a given time. Hence, both the LSH and PSH per reference 2 are necessary.
52	> flare pressure	R	–	–	R	In this situation, since the pumpage vapor pressure will always be > maximum flare pressure, the leaked media will always be vapor. As such, the LSH requirement per Reference 2 is not essential. An PSH is mandatory.
52	< atmospheric pressure	–	–	R	R	In this situation, since the pumpage vapor pressure will always be < atmospheric pressure, the leaked media would always be liquid. As such, the PSH requirement per Reference 2 is not essential. A LSH is mandatory.
53A	> atmospheric pressure	–	R	–	R	In Plan 53, flare pressure does not matter. In this situation, in case the plan 53 pressure source fails at the same time the PSL also fails and the inboard seal leaks, even then the LSH would never function since the leakage would never be in liquid form. As such LSH requirement per Reference 2 is not essential.
75	< atmospheric pressure	–	–	R	–	In this situation, since the media vapor pressure will always be < atmospheric pressure, the leaked media would always be liquid. As such, the PSH requirement per Reference 2 is not essential. An LSH is mandatory. A level transmitter would be recommended in place of a level switch to have a precise measurement/recording.

R: Required **Note:** Plan numbering is as per (1). Flare pressure varying and assumed always to exceed atmospheric pressure.

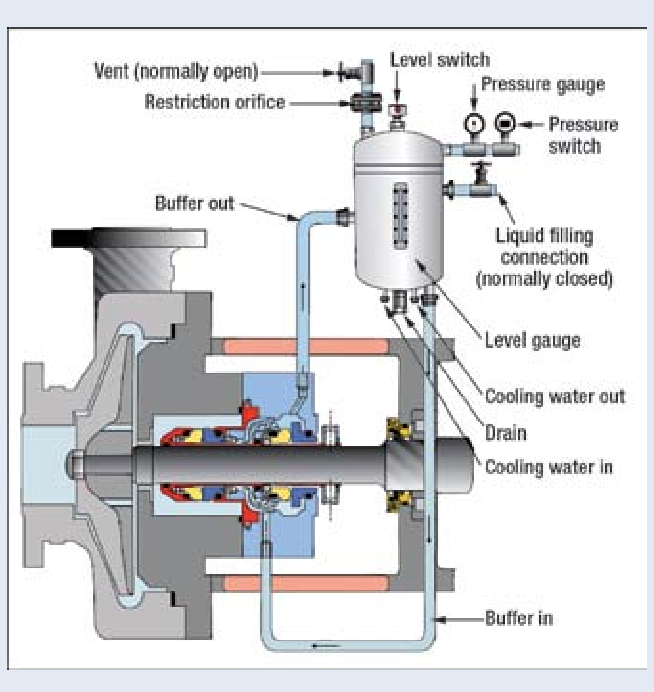


FIG. 5 API Plan 52—Depressurized buffer-fluid circulation in a dual-seal outboard section through a seal-support system. A pumping ring maintains circulation while running; thermosiphon action is effective at standstill.

always stay well below atmospheric pressure and this proved the PSH to be redundant.

Doing away with the PSH prompted the authors' facility to determine all pump seal-related instrumentation requirements based on flare and vapor pressures. Moreover, the company decided to enlist the help of pump and seal manufacturers. The information compiled in Table 2 can be useful, but it points to the need for all parties to interact and consult when selecting instruments for Plans 52 (Fig. 5), 53A[2] and 75 (Fig. 4), all of which incorporate pressure switches.

There could also be applications where a high-level transmitter (LTH) might be preferred to an LSH. Again, cooperation between the interested or affected parties will help define what is best.

Case 4: Plan 75 for Plan 52. Applications involving mechanical seals in light hydrocarbon duties can be provided with Plan 52, as well as Plans 75 and 76, wherein vapor leakage from the inboard segment of a dual-containment seal is directed to a suitable vapor-recovery system.[2]

Containment seal effectiveness provided with Plans 75 and 76 from emission and reliability viewpoints is satisfactory.[8] Reference 8 is among several that acknowledge the suitability of contacting (faces wetted by liquid) as well as non-contacting (faces separated by a gas) containment seals for many applications. Nevertheless, there is often a significant difference in liquid containment (that may occur in a primary seal failure) between noncontacting and contacting sealing devices.

The typical LCC comparison for contacting-type seals and Plan 75 vs. Plan 52 is given in columns 3 and 4 of Table 1. Plan 75 is provided with an LSH, but without a PSH—and Plan 52 with an LSL and LSH, but without a PSH. In the case discussed here, the cost comparison favors Plan 75 and the same trend is observed for Plan 76. Maintenance associated with seal repairs, filling, draining and flushing a contaminated buffer system can be considerable.[2]

Based on the above discussion, it is worth probing substituting Plans 75 or 76 in place of Plan 52. An end user, however, should take into account certain failure scenarios. In case of Plans 75 or 76, inboard seal failure would require shutdown and maintenance within a short period. In contrast, and with Plan 52, safe pump operation might be continued for longer.

Moreover, the containment-seal condition in Plans 76 or 75 is neither known nor monitored by these plans. If the containment seal is faulty and the inner seal fails, there is a potential for containment loss. With Plan 52, the outer seal condition is continuously monitored by the seal pot liquid level. This safety feature of Plan 52 is an important point.

Finally, Plan 52 only works well on vaporizing leaks; Plan 76 should only be used on vaporizing leakage, whereas Plan 75 is used for condensing leakage.

Case 5: Misunderstandings on Plan 53B ("M"). Reference 9 describes piping schematics for seal assemblies or configurations that collect both liquid and vapor leaks. The resulting Plan 53B (sometimes labeled "M") layouts may or may not require a heat exchanger. In contrast, an exchanger is invariably needed for buffer/barrier liquid cooling with Plans 52 and 53A. Buffer/barrier reservoirs of 20 liters (5 gallons) for all pump shaft diameters were used due to inherent advantages (Reference 10) including standardization of sizes.

It should be noted that piping connections are often provided with Plan M, although cooling may not be required in many applications. As a general rule, Plan "M" is not required for pumpage temperatures below 45°C, while from 45°C to 70°C, checking the feasibility of an air-fin cooler may be of merit. The cooling-water consumption for Plan "M" can be 10 liters/min. and the typical LCC for five years with Plan "M" is mentioned in column 5 of Table 1. Note that the resulting expenditure might not be incurred. The benefits of eliminating cooling requirements certainly deserve more of our attention.[3,4]

Again, a careful review of pumpage property (temperature, stuffing-box and vapor pressure range in the anticipated operating temperature range) and buffer/barrier liquid properties is advised. Knowing the coking tendencies of many fluid media at elevated temperature will enable seal manufacturers to determine if cooling is needed with Plan "M" configurations. The responsible entity (pump manufacturer or design contractor) must furnish these details to the seal manufacturers at the bidding stage so that a well-informed decision can be made about using Plan "M."

Case 6: Tapered stuffing boxes. Suppose the conventional seals fail prematurely because a slurry or random solid particles are present in the pumpage. The seal manufacturers recommend solutions such as double seals with Plan 53A/B/C[2], single seals with Plan 32[2] a stuffing box with baffles and seals provided with solid separator bushings.

A tapered stuffing box offers several advantages and is usually recommended for slurry applications.[6,11] Some limitations for tapered stuffing boxes include noncompliance with API-610.[9] In a typical case, one pump manufacturer offered a pump with a 45-degree tapered stuffing box with an integral vortex-breaking rib with Plan 32, as against a conventional cylindrical stuffing box with Plan 32. A tapered seal chamber with vortex-breaking baffles is self-flushing, self-venting and self-draining. Moreover, the configuration modifies the flow at the seal chamber end and nearest to the seal faces for improved effectiveness. A careful review revealed that pumpage slurry content was low enough to do away with Plan 32 for a tapered stuffing box, leading to substantial savings in utilities and initial investment. The substantial combined cost savings prompted users to select a pump with a tapered stuffing box instead of a pump with the more typical cylindrical seal environment.

In summary, real-life case studies prove that it is possible to make more-informed choices that very often lead to cost savings. These choices can be made from available options and, as long as they deal with proven experience and are well thought-out, the choices may indeed deviate from the more general conventional guidelines. **HP**

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