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# Optimize Energy Costs in Petroleum Refineries

Improve refining margins with more energy efficient measures

By Ven V. Venkatesan

**P**etroleum refining is a highly energy-intensive process using both purchased energy (gas and electricity) and byproduct streams from the refining processes. Energy use accounts for approximately 50% of refining costs. As major energy suppliers, refineries must report and monitor self-consumption of energy as a percentage of their total crude intake for processing. A modern refinery is a highly complex but integrated system, separating as well transforming heavier hydrocarbons into saleable fuels and chemicals. Improving energy efficiency in a refinery is very critical, as it directly relates to sending more products to the market. A refinery monitors its profitability by evaluating its refining margin. When more saleable products are sent out, the net refining margin increases. Blending, process heating, dis-

tillation, cracking, reforming, absorption, evaporation and cooling are typical processing operations involved in petroleum refineries.

Many improvement opportunities at petroleum refineries apply at other process plants as well. Typical among them are burner tuning at the fired heaters. While most large heaters, like crude-unit charge heaters, are monitored well, small process heaters are seldom monitored for optimum excess air levels. Many smaller fired heaters don't have enough heat recovery features and release high-temperature flue gases directly to the atmosphere.

Recovering heat from the blowdown water of various boilers and waste-heat steam generators is another common way to save

## Improving energy efficiency directly relates to sending more products to market.

energy. In a large petroleum refinery in Louisiana, the continuous blowdown water from two fuel-fired boilers and two waste-heat boilers directly drained to the sewer. The refinery already was experiencing excess 50-psig steam generation, so it had no incentive to recover additional flash steam. Hence, we recommended recovering the waste heat from the blowdown water for better utilization of the excess low-pressure steam.

Because coker drums need large quantities of water for cutting and washing the coke, we also recommended routing the blowdown water to the coker for this purpose, saving fresh water and reducing the sewer load.

At the same refinery, the high-pressure (600- and 350-psig) and medium-pressure (150-psig) condensate collection lines from various steam users are routed to a common collection vessel. Flash steam venting from this tank was substantial. We recommended installing a new flash tank upstream to the existing condensate collection tank to handle the high pressure condensate. The level controller in the new flash tank would route the condensate to the existing condensate tank after separating the flash steam. This kind of flash steam

recovery may suit other refineries, too. Minimizing the use of low-pressure (LP) steam condensing is another possible way to cut energy costs. Excess LP steam is a common problem, so many refineries opt for air-fin type condensers to reject the heat in steam and recover the liquid condensate. By reviewing the steam users, it may be possible to replace some of the medium-pressure steam users with low-pressure steam or find some additional use for low-pressure steam. In this refinery, two air-fin condensers cooled the excess 29-psig steam and one air-fin condenser cooled the liquid condensate to minimize water hammer before it was sent to the secondary scrubber. Diverting excess steam to the 22-psig steam header and routing the liquid condensate to the scrubber without cooling helped stop the heat rejection at the condensers.

Process units in refineries often are widely spread out, demanding lengthy steam supply lines. Occasionally, the headers supplying steam to far away locations experience excessive heat and steam trap loss. The steam supply quality also deteriorates, especially to remote consumers.

In this refinery, the dock area and the tank farm were more than 1½ miles away. We

## Process engineers should give priority to optimizing the steam balance.

recommended installing a small LP package boiler near the dock area with a water softener to feed the boiler. The new package boiler isolated the mile-long steam supply header. Similar opportunities also may apply at other refineries with widely spread out process units.

### **IMPROVE CONDENSATE RECOVERY**

A common energy issue I've observed in petroleum refineries is low condensate recovery from steam users. Typical steam condensate recovery ranges from 20–45%, but the recovery potential is around 75%. Steam users such as heat tracer lines, tank farm heating coils and exchangers, and remote heat exchangers generally don't return condensate back to the boiler. Most of these refineries were designed 30 years ago, when energy prices and boiler feed-water treatment costs were low. Wastewater disposal also wasn't an issue to many remote operations. With present day environmental concerns, sites should put a priority on reconsidering draining reusable, good quality boiler feed water to the wastewater system.

Because heat tracers are supplied with steam at constant pressure without any

modulation, collecting and returning the condensate from the tracer traps is a simple task — if the tracer system is organized well. Proper steam supply and condensate collection manifolds can help revamp old and unorganized heat tracing systems. A proper steam tracer system design not only enhances condensate recovery, but also improves system maintenance and helps quickly prevent unexpected process failures that could happen during severe winter storms.

Collecting and returning condensate from tank farm heaters is another energy efficiency improvement. In one Caribbean refinery I worked at, all fresh water, including boiler feed water, was made from distilled sea water. Circulated sea water was used to cool all process heat exchangers. Condensate recovery was still around 20%. Because the return headers and pumps were not maintained, they had become obsolete, resulting in several tank farm heaters collecting the condensate, but draining to the local sewers. In this situation, new condensate pumps and additional pipelines could return the condensate back to the utility plant. Even pumping the condensate to nearby process units for internal fresh water use would save marginally the expensive sea water generation.

When steam users at remote locations use steam at different pressure levels, it's likely that the low-pressure (LP) steam users are draining condensate to the grade. It's typical for the initial utility system design to provide a single condensate return header with limited margins to collect and return the condensate. Over a period of plant expansions with condensate sources at different pressures, the return system wouldn't be able to handle condensate at all pressure levels. In this case, reassess the condensate handling capacity of the return system and make suitable modifications such as adding segregated pipelines, flash tanks and pumps. This reengineering action would not only enhance the condensate recovery, but also help eliminate problems like water hammer and unsafe pipeline ruptures.

To further reduce energy costs and improve energy efficiency, consider reevaluating the low-level (LL) heat rejections to atmosphere from various process units. Exhaust gases from process heaters' heat recovery coils, and distillation column exit streams that need cooling and condensing constitute the LL heat rejection sources. Because the existing heat recovery coils and heat integration exchangers were designed based on temperature limits set decades ago, reevaluating the heat rejection temperatures at the present energy cost levels would be a worthy exercise.

Occasionally, a suitable reuse option for the rejected LL heat may exist in a neighboring process unit. If the fuel gas system consistently contains increased valuable light ends such as propane and butane, better overhead vapors cooling would help recover these light ends from the fuel gas. The rejected LL heat would help run an absorption chiller and improve overhead vapors cooling. Many petroleum refineries, especially in southern states, are considering adding absorption chillers that use the LL heat presently rejected from their process heaters and air-fin condensers.

Reviewing the steam system balance may open up multiple energy-saving opportunities. Petroleum refineries utilize steam at several pressure levels ranging between high and low. To reduce these energy losses, pay close attention to the number of operating steam turbines that lead to LP steam venting, and continuous use of pressure-reducing valves to obtain LP steam from high-pressure headers. Process engineers should give priority to optimizing the steam balance to minimize both situations. Petroleum refineries offer endless options for energy cost reduction. ■

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# Understand the Changes in API RP 754

The second edition of this standard on process safety performance indicators contains some important revisions

By Kelly K. Keim, ExxonMobil Research and Engineering, on behalf of the American Petroleum Institute

In 2010, the American Petroleum Institute (API) issued “Recommended Practice (RP) 754: Process Safety Performance Indicators for the Refining and Petrochemical Industries” [1]. This standard has gained broad acceptance and use not only by the refining and petrochemical sectors in the United States but also by other sectors of the energy industry and by other process industries in the U.S. and around the globe.

The drafting committee recognized the entirely new nature of this standard and believed its use would lead to valuable insights that a second edition should reflect. So, the standard was re-opened in August 2013 after two complete years of data collection, and the committee considered a variety of revisions. Here’s a guide to changes

in the second edition, which was published in April 2016 [2].

From the very beginning, committee members agreed that the standard is not broken, as demonstrated by its rapid voluntary adoption by many organizations and companies around the world. However, many ideas for potential improvements were suggested, including expansion of the standard for application to petroleum pipeline and terminal operations, retail service stations, and oil and gas drilling and production operations. These enhancements appear in the second edition; individual annexes define appropriate changes to the applicability and definitions sections of the RP tailored to those specific operations. Other recommendations for improvement spanned the desire for greater clarity in application of



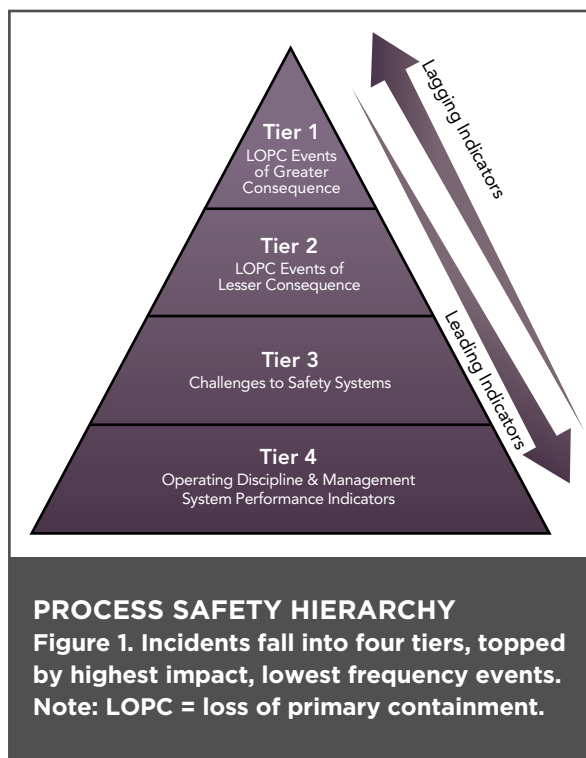
the standard to the many facets and nuances of process safety, additional guidance regarding identification and use of Tier 3 and 4 (Figure 1) leading indicators, more examples of process safety event (PSE) tiering to address questions brought forward in quarterly RP 754 webinars hosted by the API and American Fuels and Petrochemical Manufacturers (AFPM), and a few targeted changes to the criteria used to define Tier 1 and 2 PSEs.

## KEY CHANGES CONSIDERED

The three most-complex proposals for change subjected to formal balloting were:

1. *Increasing the direct cost damage threshold for fires and explosions for Tier 1 from \$25,000 to \$100,000.* This change was approved. Fires and explosions with direct cost damages between \$25,000 and \$100,000 move to Tier 2. The \$2,500 threshold value for Tier 2 fires and explosions remains unchanged — so the total of events captured in Tier 1 and Tier 2 stays the same. The committee believes that changing the threshold to \$100,000 places the significance of this category of PSE more on par with the other criteria for Tier 1.

2. *Use of the hazard class designations from the globally harmonized system for classification and labeling (GHS) to designate threshold release categories (TRCs) for tiering of releases by quantity released.* No proposed change was more thoroughly studied or



actively discussed than this one. Many of the existing TRC criteria (e.g., Tier 1 TRC 2, 3 and 4 for toxic inhalation hazards; TRC 5, 6 and 7 for flammable gases and liquids; and TRC 6 and 7 for skin corrosion) already are based upon the same criteria used in GHS. Criteria for other health hazards such as oral ingestion toxicity, respiratory and skin sensitizers (Class 3.4), germ cell mutagenicity (3.5), carcinogenicity (3.6), reproductive toxicity (3.7), specific target organ toxicity for single and repeated exposures (3.8 and 3.9), and aspiration (3.10), as well as environmental hazards to the aquatic environment (4.1) and the ozone layer (4.2) proved more difficult. A key feature of the criteria for delineating thresholds for inhalation toxicity, flammability of gases and liquids, and skin corrosion is that the intensity of the hazard level posed by the

materials in categories within each GHS class is represented and used to differentiate TRCs. No categorization exists within health hazards 3.4 to 3.10 or in environmental hazards 4.1 and 4.2 to differentiate the intensity or potency of those hazards. For example, the carcinogenicity of ethanol would be treated the same as that of 1-azoxypropane, which some studies have indicated has a potency eight orders of magnitude higher as measured by median toxic dose ( $TD_{50}$ ). The same holds true for environmental hazard classes 4.1 and 4.2. Inclusion of oral toxicity by ingestion in assigning the significance of a PSE also proved problematic. Ultimately, the committee determined that RP 754 should remain focused on acute process safety impacts such as flammability versus potential chronic impacts to health and the environment that require extended exposures. In the end, the committee rejected several proposed alternatives for basing TRCs on inclusion of all GHS classes as unsound indicators of the significance of a PSE.

*3. Use of a severity index to provide a relative indication of the significance of a Tier 1 PSE for which a minimum threshold is defined but is open-ended on the high side.* Section 5.2 of RP 754 sets the minimum threshold of consequences for an event to be considered a Tier 1 PSE; however, the consequences of PSEs are open-ended on the high side. The Center for Chemical Process Safety (CCPS) booklet “Process Safety Leading and Lagging Metrics ...You Don’t Improve What You Don’t Mea-

sure” [3] contains an example of a severity index that provides a method for distinguishing those Tier 1 PSEs of higher consequence from those that just meet the criteria. The first edition of RP 754 cites this CCPS version of a severity index as potentially providing additional useful information about Tier 1 PSEs that may help drive improvement. Because several companies and industry associations have found value in the use of a severity index, a sub-team was formed to generate one to include as Annex D in the second edition. The committee considered making the use of the severity index a requirement for conformance with the document for reporting of Tier 1 PSEs; this proposal did not pass, though. Individual companies and industry associations must make their own decisions regarding collection and use of the severity index information for Tier 1 PSEs.

## **OTHER IMPORTANT REVISIONS**

A few substantive changes were made to the threshold quantities (TQs) in Tables 1 and 2 used as criteria for classifying Tier 1 and 2 PSEs.

- TQs for indoor releases in Tier 1 were lowered from 50% of the outdoor quantity to 10% based on analysis of dispersion modeling that showed that consequences similar to those of outdoor releases of Tier 1 TQs could be reached at the lower threshold, even for enclosures with good ventilation. No change was made to the ratio of indoor versus outdoor TQs for Tier 2.

- Due to their ability to create large zones of an asphyxiating atmosphere when large releases occur, particularly when in liquid form, UNDG Class 2, Division 2.2 non-flammable, non-toxic gases excluding air were added to TRC 7 for Tiers 1 and 2. The relatively large masses associated with TRC 7 put smaller uncontrolled releases of materials like nitrogen that do not pose a safety or health threat below the threshold for reporting for Tier 1 and 2.
- Another change affects only Table 2 TQs for Tier 2. Liquids with a flash point >60°C (140°F) released at a temperature below flash point and moderate acids and bases are included in Tier 2 PSE reporting but not in Tier 1. Because of a desire to prevent proliferation of TRCs, Tier 1 TRCs 6 and 7 materials were collapsed into a single TRC 6 at Tier 2 in the first edition. This created confusion within the standard rather than minimizing it. So, the second edition provides separate TRCs 6 and 7 at Tier 2 just as for Tier 1. The result is that

liquids with a flash point >60°C (140°F) released at a temperature below flash point and moderate acids and bases become TRC 8 at the Tier 2 level. In addition, the second edition sets a maximum flash point of 93°C (200°F) for inclusion of materials into the new TRC 8.

The committee also reexamined the use of workforce hours for normalizing rates of Tier 1 and 2 PSEs. The additional years of data collected since the first edition came out showed that workforce hours provided substantially the same results as any other proposed normalizer. Moreover, industries using process safety indicators well understand and track workforce hours. So, it was retained in the second edition.

Changes were made to the required data capture for Tier 1 and 2 PSEs; these include fine-tuning the list of refinery and petrochemical processes, additional breakdown of “normal” modes of operation, and refinements in the list of equipment to be identified as the

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point of release. Of particular note, piping now is separated into large bore (>2-in-dia.) and small bore ( $\leq$ 2-in-dia), in part because piping has been the most common point of release and degradation modes often differ between large- and small-bore piping. Sites now are expected to record an event description and assign causal factors chosen from a list provided in the standard.

The experiences of several companies in implementing Tier 3 and Tier 4 indicators prompted the committee to include a substantial amount of new guidance on these indicators' selection and use. This appears in Annexes I and J of the second edition. Ten example Tier 4 indicators are cited, with each having a definition of the indicator, its intent, means of data capture, example calculations, suggestions for indicator drill-down, the intended audience, recommended measurement frequency and potential unintended consequences. In addition, the new content includes an example of detailed analysis and interpretation that affords greater learning and understanding of the causes and trends of PSEs that result in more-effective action to prevent them.

All other changes in the second edition are intended as clarifications of the intent of the first edition. Many originated from questions or comments raised at the quarterly webinars that have been hosted by API and AFPM. Contact Lara Swett at [LSwett@afpm.org](mailto:LSwett@afpm.org) about participating in a webinar.

Clarifications include the provision of a definition of "responsible party" useful in determining who should report a Tier 1 or 2 PSE when an event occurs where multiple parties may play a part in the work performed at a site. A definition of "active staging" clarifies the difference between events in the transportation of materials versus those considered to be on-site storage and activities involved in connecting and disconnecting to a process for the purpose of material transfer. Events occurring during active staging are considered to be transportation events, not process safety ones. "Active warehouse" has been added to the definition of "process" to better reflect operations more typical of traditional chemicals manufacturing where containers of materials may be delivered to, used in processing, and shipped from within a single on-site structure. Additional guidance also is provided in the identification of those events involved in the construction of new facilities that must be reported as Tier 1 or 2 PSEs.

The concept of "precautionary evacuation or precautionary shelter-in place," which reflects measures taken in an abundance of caution, has been introduced into RP 754. Those actions considered precautionary are excluded from consequences when taken by on-site personnel but are identified as consequences when taken to protect members of the public. Damages from fires and explosions now must consider acute environmental cost, including short-term cleanup and material disposal associated with a loss of primary contain-

ment with off-site environmental impact. Events related to overpressure releases to the atmosphere, either directly or through downstream destructive devices, now must consider safety instrumented systems and other engineered depressuring along with pressure relief valves and rupture disks.

Tables 1 and 2 now include a footnote to indicate the hierarchy intended for the use of packing group versus material properties expressly described: “In determining the Threshold Release Category for a material, one should first use the toxic (TIH Zone) or flammability (Flash Point and Boiling Point) or corrosiveness (Strong Acid or Base vs. Moderate Acid or Base) characteristics. Only when the hazard of the material is not expressed by those simple characteristics (e.g., reacts violently with water) is the UNDGL Packing Group used.” Guidance for the application of TRCs to multicomponent releases appears in Annex G. That annex covers gases with toxic components, flammable gases, asphyxiant gases, flashing

liquid streams containing toxic inhalation hazards, flammable liquids, and multicomponent streams with both flammable and inert liquids, e.g. water. This includes liquids with a distinct phase of flammable liquid, streams containing flammable components dissolved in inert liquids, streams with stable emulsions of flammable components and inert liquids and solutions.

The API RP 754 committee hopes the second edition of the standard leads to more universal adoption by process industries and serves as an even more effective tool for all parties interested in learning from and preventing PSEs. Tracking of PSEs, as defined within RP 754, and analysis of the aggregate data required for reporting is the first step in identifying corrective actions to prevent recurrence. ■

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3. “Process Safety Leading and Lagging Metrics ...You Don’t Improve What You Don’t Measure,” Ctr. for Chem. Proc. Safety, Amer. Inst. of Chem. Engrs, New York City (2011). [www.aiche.org/sites/default/files/docs/pages/metrics%20english%20updated.pdf](http://www.aiche.org/sites/default/files/docs/pages/metrics%20english%20updated.pdf)

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# Head Off Hydrogen Hazards

Proper material selection and piping design are crucial

Increased reliance by refineries on heavy crude has led to greater use of hydrogen. This, in turn, has resulted in a rise in accidents related to hydrogen-based unit operations. For instance, on April 2, 2010, seven workers were killed when an exchanger in the naphtha hydrotreater unit at Tesoro's Anacortes Refinery in Anacortes, Wash., ruptured, releasing naphtha and hydrogen that exploded. High-temperature hydrogen attack (HTHA) was blamed for the accident. A fire that occurred on October 6, 2011, at the Co-op Refinery complex in Regina, Saskatchewan, due to a 7.5-in. rupture in a pipe containing H<sub>2</sub> and H<sub>2</sub>S, injured seven workers. Authorities fingered corrosion as the cause. What's particularly scary is that

this section of pipe recently had passed inspection.

These and other incidents are spurring engineers to develop stringent controls on pipe and equipment used in H<sub>2</sub> service. So, let's look at some best practices.

For hydrogen pipelines and process operations involving low-to-moderate pressures and temperatures, the main risk is hydrogen embrittlement or hydrogen-assisted stress corrosion cracking. HTHA is the predominant danger at temperatures above 250°F. (Some sources say HTHA begins at 400°F.) In HTHA, methane forms at interfaces where carbon accumulates. Each form of attack creates hardening and

## What is particularly scary is that this section of pipe recently passed inspection.

stress concentration that promote metal damage. Stress corrosion cracking is a symptom not a cause.

The risk of failure increases with hardening caused by: 1) welds that are several times harder than parent metal; 2) welding that disturbs the microstructure of the virgin metal, thereby promoting H<sub>2</sub> access; 3) cold working that creates fine cracks, allowing H<sub>2</sub> access; and 4) the presence of H<sub>2</sub>S, which can cause blisters as hydrogen accumulates in metal. It's important to differentiate between pipe and equipment handling sour steams, i.e., ones with high H<sub>2</sub>S, and those with low H<sub>2</sub>S.

API 5L X52, ANSI 310 and other low-strength steels have been used in ambient H<sub>2</sub>-only pipeline applications. A useful guide for carbon steels, strictly in hydrogen service, is the Nelson diagram in API-941.

HTHA is a problem in high-pressure, high-temperature, low-H<sub>2</sub>S applications, such as hydrotreaters and even high-pressure boilers. Nickel-iron-chromium (~22%) alloys work well in such conditions (e.g., <1,500 psig, 750°F, trace H<sub>2</sub>S typical in a hydrotreater furnace). Stainless steels also are options. Austenitic (stainless)

steels, containing >5% chromium, tie up carbon effectively; hydrogen diffuses more slowly in austenitic than in ferritic (carbon) steels. Type 316L sometimes is recommended for temperatures exceeding 250°F; avoid it for high-pressure applications because its allowable strength decreases by 19% from 300°F to 1,000°F.

Type 316L and even 304L stainless steels get chosen for low-to-moderate temperature, low-to-moderate pressure applications; type 304L is far less resistant to cold-working damage.

What material should be used in high-pressure, high-temperature, high-H<sub>2</sub>S applications? Austenitic stainless steels are preferred in hydrotreating and hydrocracking services: ANSI types 304, 321 and 347 have been used in cladding or weld overlays for furnace coils operated up to 3,000 psig and 850°F; type 347 generally is considered the best choice. Washing in weak base (ammonia) is required during hydrotreater shutdowns to avoid polythionic acid intergranular cracking.

Now, consider the following general design criteria for H<sub>2</sub> pipe: 1) threaded joints are unacceptable; 2) gaskets at the few raised-face flanges should consist of



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two soft deformable seals surrounding a serrated solid metal ring, i.e., a ring-type joint, or metal/metal for pressures exceeding 100 psig; 3) hard metal gaskets are necessary — for fire risk and because soft metals like copper and materials like graphite are permeable to H<sub>2</sub>; 4) butt-welds should be used (socket welds concentrate loads at sharp edges); 5) choose seamless carbon steel pipe, like API 5L and ANSI 310, where applicable, or electric-fusion-welded pipe for diameters of 16 in. and above, and mandate post-

weld heat treatment as well as full x-ray inspection of all welds; 6) valves should employ bellow stem seals and be of a rounded bonnet-and-crotch design to avoid stress concentrations; 7) avoid gate valves and checks as they generally aren't useful; and 8) specify a minimum flange rating of 300 ANSI for all pipe, and go one ANSI rating above design pressure when it exceeds 300 psi. ■

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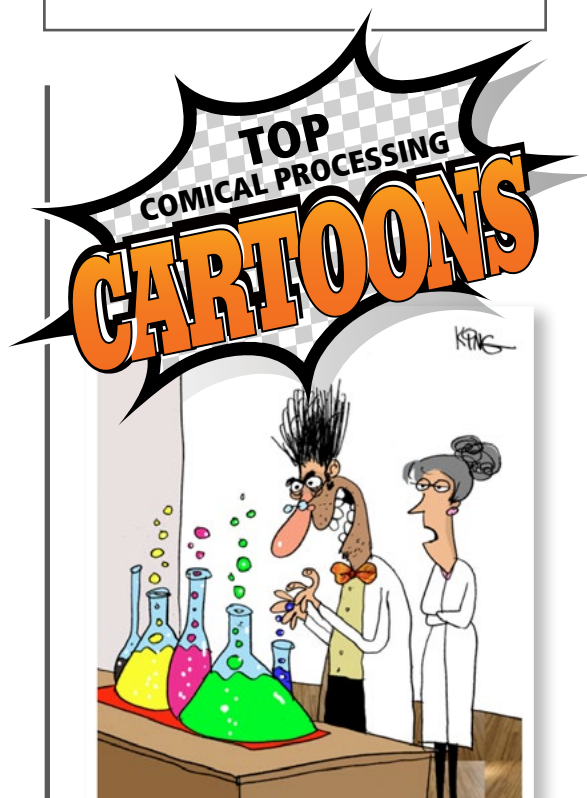
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