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EXECTUIVE BRIEF

Maintaining Productivity Yields Through Instrumentation Analysis

Instrumentation repair, maintenance, or replacement is a key essential of any project or plant operation analysis. Whether you are measuring existing energy consumption norms in gas pipelines, scoping a maintenance turnaround, or defining criteria design and conditions, all procedures and resulting analysis are measured to safety and maximize your capital return.

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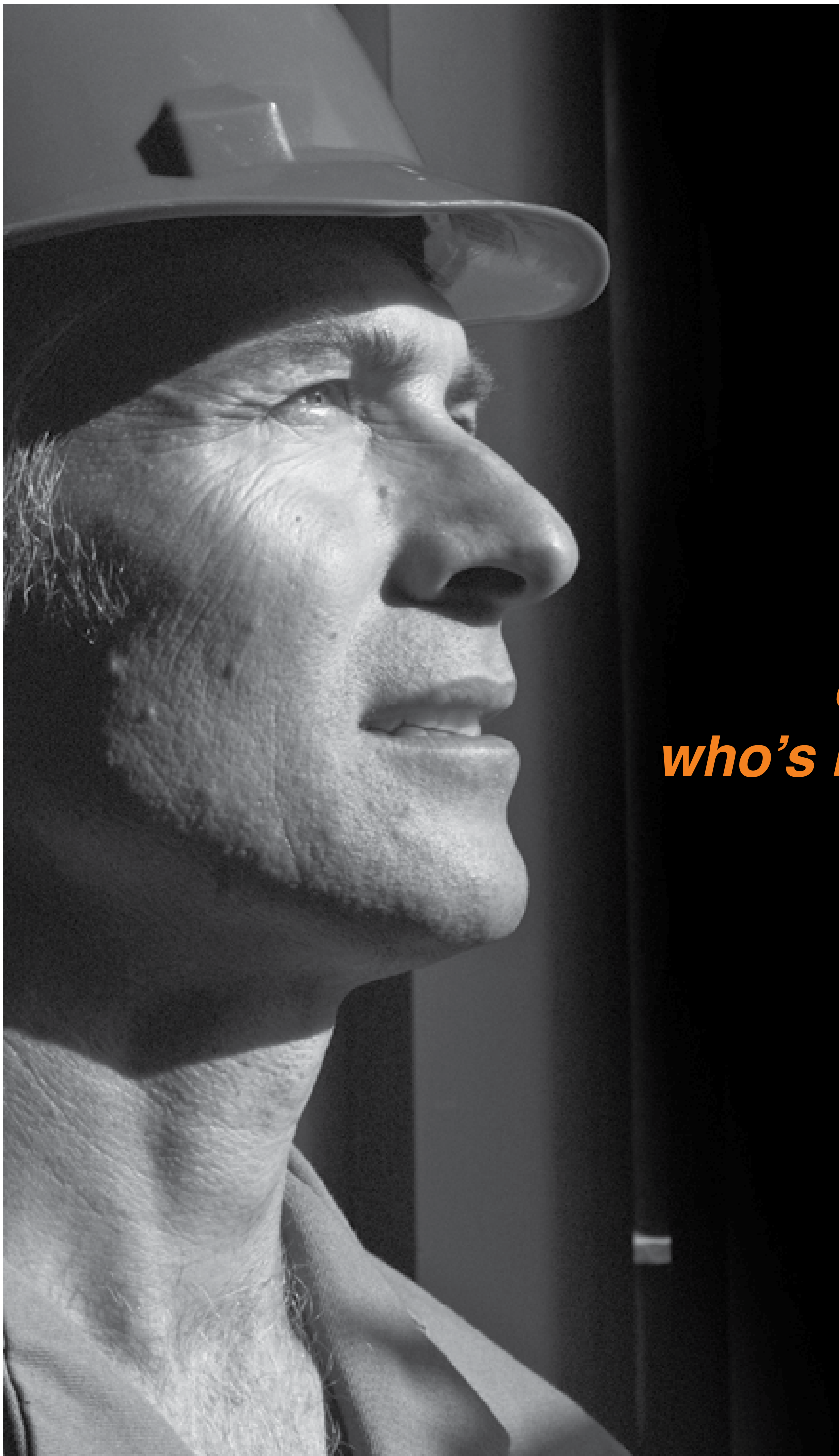

Originally published February 6, 2012

The pursuit of 'zero leaks'

by **CHRISTOPHER E.** Smith

US PRESIDENT BARACK Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 into law Jan. 3, reauthorizing the Department of Transportation's existing pipeline safety programs through 2015 while also placing new requirements on both pipeline operators and regulators.

On the operators' side of the ledger, the law increases maximum penalties for individual violations to $200,000 from $100,000 and for a series of violations to $2 million from $1 million. It also requires gas transmission pipeline operators to report within 18 months any pipeline segments with insufficient maximum allowable operating pressure (MAOP) records, to report incidents pushing operating pressure beyond MAOP within 5 days of their occurrence, and to consider seismic activity when evaluating pipeline threats.

DOT requirements

Among the requirements placed on DOT regulators, meanwhile, was maintaining a map of high-consequence areas (HCAs) on the National Pipeline Mapping System (NPMS) and to develop an NPMS awareness program within a year. It also requires DOT within 18 months to both develop guidance for operators to share system-specific information with emergency responders and establish time limits on leak and accident notifications to both emergency responders and other state and local officials.

The timeline to establish requirements for gas transmission pipeline operators to confirm their pipelines' physical and operational characteristics, including MAOP, for pipelines in Class 3 and 4 zones and HCAs is even shorter at 6 months. This relatively short timeframe recognizes increased public awareness of pipeline safety in the wake of significant accidents on both oil and gas pipelines.

The law also requires DOT's Pipeline and Hazardous Materials Safety Administration to issue new pipeline safety standards requiring operators to install automatic or remote-controlled shut-off valves and excess flow valves in new or replaced transmission pipelines. It also authorizes $110 million/year in safety related grants for use by states in damage prevention programs, emergency response training, technical outreach to local communities, and one-call system improvements.

The promulgation of such programs on a state level has leapt in importance in areas like the Eagle Ford and Marcellus shales, where pipeline development has gained momentum as operators seek to bring their gas and liquids to market. Cooperation and coordination among states also is important, particularly in areas like the Marcellus where a single, relatively small project can often cross multiple state boundaries.

Pennsylvania acts

Pennsylvania Gov. Tom Corbett signed his state's "Gas and Hazardous Liquids Pipelines" Act into law in December 2011, authorizing its public utility commission (PUC) to conduct pipeline safety inspections in coordination with PHMSA and to regulate pipelines without declaring them a public utility. This latter point was particularly important given concerns from property owners regarding imminent domain, which public utilities can exert. If the PUC had been allowed to regulate only pipelines designated as utilities many would have gone uncovered (bad for safety) or had to have been reclassified as utilities (bad for property owners).

Now that the property owners' rights have been preserved, it is incumbent on them and their communities to live responsibly in the company of the new pipelines. The safety-related money authorized for disbursement to states through PHMSA under the new federal pipeline safety law can help this happen.

Both the federal law and its Pennsylvania counterpart are encouraging. Not just because they help codify the importance of pipeline safety, but because they recognize that it is best achieved as a partnership: between regulators and operators, between the federal government and smaller jurisdictions, and finally, between all of these and the citizens at large.

Colonial Pipeline Co. Chief Executive Officer Tim Felt once aptly described "zero leaks" as the only reasonable goal for the US pipeline industry (OGJ Online, Mar. 25, 2009). Without each of these parties' active participation, this goal cannot even be seriously approached, much less attained.

CHRISTOPHER E. SMITH is Pipeline Editor for Oil & Gas Journal.

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COMPRESSOR OPTIMIZATION—1 Energy recovery guides natural gas pipeline system efficiency

by **SHAGHAYEGH KHALAJI**

ECONOMIC ANALYSES DEMONSTRATE the operational benefits of using particular energy recovery and scrubber technologies on natural gas transmission systems. The first article of this series, presented here, details these analyses as applied to Iran's gas system. The concluding article will focus on the effect of scrubbers and other equipment in attempting to maximize capital return.

Background

Iran is one of the largest consumers of natural gas in the world. Several transmission pipelines move natural gas across the country, with compressor stations roughly 100 km apart. Existing information regarding gas consumption by compressor stations in Europe cannot be directly applied to Iranian stations due differences in line length and the need to first define a number of consumption indices.

NATURAL GAS VOLUMES — Table 1

Country	Shipped (MMscfd)	Consumed as fuel (MMscfd)	Consumed, %
Austria	8,118	223	2.7
US	652,373	17,638	2.7
Italy	84,897	591	0.7
Turkey	36,599	190	0.5
Czech Republic	6,216	538	8.6
Poland	16,202	389	2.4

Table 1 shows the energy consumed transmitting gas in some countries.

EXAMPLE PIPELINES — Table 2

Country	Length, km	Natural gas transferred, 1,000 cu m/day	Compressor station power, Mw	Maximum pressure, bar	Power index, Mw/ (km × 1,000 cu m/day)
China	1,084	5	24.88	50	0.00459
The Netherlands	720	8.7	32.1	69	0.00512
Romania	100	51	25	63	0.00491
US	1,200	14.3	92	77	0.00537
Algeria	520	335	822	72	0.00472
Global average					**0.004773**

Comparison, however, requires development of

IRANIAN NATURAL GAS PIPELINES Table 3

Pipeline	Length, km	Trans-ferred gas, 1,000 cu m/day	Nominal power, Mw	Power index, Mw/ (km × 1,000 cu m/day)
Line 1	400	46	160	0.008696
Line 2	656	91.7	478	0.007943
Line 3	656	90	440	0.007461
Average				**0.007905**

TEMPERATURE, REQUIRED POWER Table 4

Input gas temperature, °C.	Compressor power requirement, kw
10	39,651
15	40,679
20	41,693
25	43,692
30	43,678
35	44,653
40	45,617

suitable indices. This article compares the power required for gas transfer via pipeline by first calculating the power needed by each station per 1 million cu m gas/km/day.

Table 2 shows this power index for a variety of countries.

Table 3 shows the calculated power requirement for gas transfer of 1 million cu m gas/km/day on three Iranian pipeline networks. Iranian power requirement are about 60% more than the other countries.

Investigation parameters

The classic definition of efficiency of thermodynamic systems centers on increasing energy per unit of consumed fuel. Increases in either pressure or temperature can increase the power produced by compressor stations. Pressure is a desired increase in this context, temperature is not.

Equation 1 defines desired efficiency, an index for comparing different stations.

EQUATION

$$Ef = wp \backslash Qf + E \quad (1)$$

where:
Ef = desired efficiency
wp = desired work, or work done for pressure increase
Qf = quantity of energy from the fuel
E = station's electric power consumption

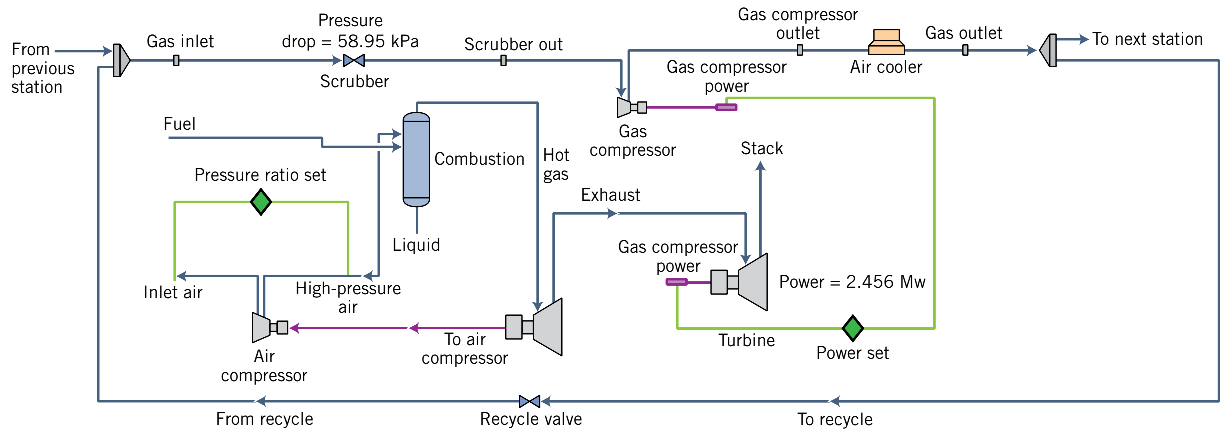
Calculating required power involves extracting enthalpy of output gas pressure and input gas temperature from thermodynamic tables and determining gas flow rate. Thermal efficiency and energy wasted in different sections of the compressor are part of this calculation.

Operational conditions

Simulating a station using HYSYS software and existing data allowed study of changing operating conditions on compressor station performance , including the

SIMULATION SCHEMATIC

FIG. 1



pressure drop in scrubber and air coolers (Fig. 1).

The following conditions governed the simulation:

:: Flow rate passing through the station, 80 MMscfd.

:: Input gas pressure, 700 psi.

:: Output gas pressure, 1,000 psi.

Table 4 shows input gas temperature's effect on compressor station power under constant pressure conditions for each period. Decreasing input gas temperature allows pressurization with smaller amounts of power. Each 1° C. decrease in input gas temperature causes roughly a 0.5% decrease in required power.

A scrubber causes pressure drop of 5-6.5 psi when clean and 18.5-24.5 psi when dirty. Compressor station simulation calculations show a 5 psi pressure drop reduces power requirements by 850 kw. Each 1 psi drop decreases compressor power requirements by 0.39%.

Compensating for the pressure drop caused by air coolers requires increasing compressor station pressure. Holding both input gas pressure to the compressor and the output gas pressure from the station constant, each 1 psi pressure drop caused by air coolers increases power requirement by about 0.27%.

ECONOMIC INVESTIGATION RESULTS Table 5

Scrubber pressure change	Compressor power saved, kw	Equivalent gas saving, cu m/day	Annual gas saving, cu m
10 psi decrease	1,682	12,615	4,604,475
5 psi decrease	845	6,338	2,313,188
5 psi increase	–853	–6,398	–2,335,088
10 psi increase	–1,714	–12,855	–4,692,075

Sensitivity analysis

Sensitivity analysis used a gas thermal value of 36,000 kilojoule/cu m and gas turbine efficiency of 32% (based on the average of installed compressors) to investigate solutions for decreasing compressor power requirements. Cooling input gas by 1° C. yielded roughly 55,000 cu m/year gas savings.

Researches also investigated pressure drop in the scrubber stemming from nonobservance of design principles and, in some cases, failure to replace the scrubber filter in a timely manner. Table 5 shows scrubber pressure drop's effects on turbine performance.

This article only investigates pressure drops up to 25 psi, but field observations show drops as large as 30-50 psi in scrubbers.

Study included investigating reduced pressure drop in air coolers, holding input gas pressure to the compressor and output pressure from the station constant. Calculations show each 1 psi pressure drop in air coolers saving 315,000 cu m/year of natural gas.

Energy loss

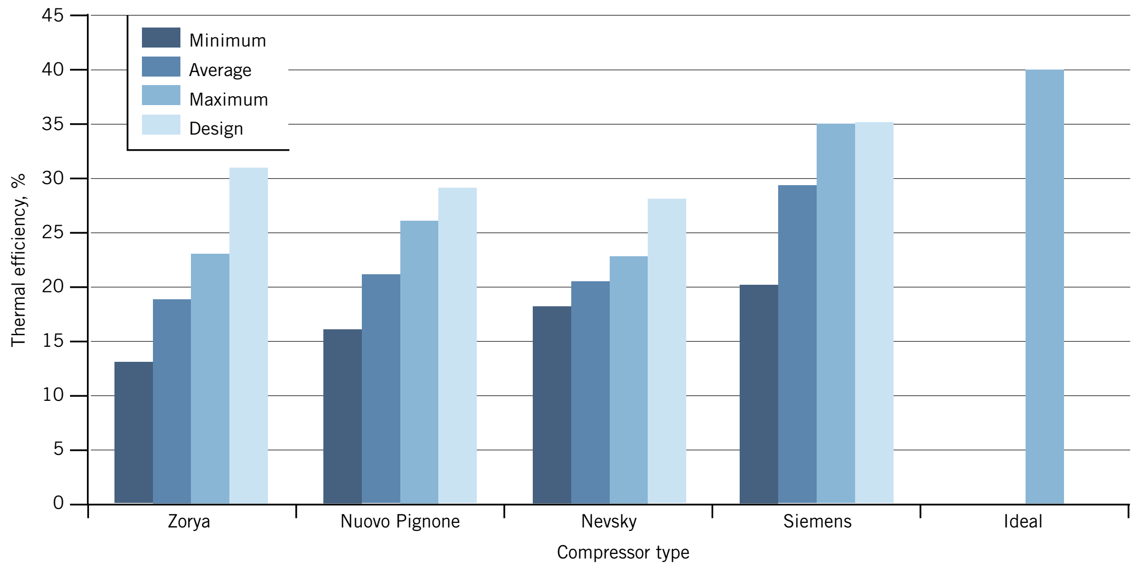
Determining energy balance is the best way to compare design conditions and optimum operational conditions and to calculate energy loss.

After investigating global energy consumption norms in gas transfer projects and determining the essential indices and parameters affecting operational conditions, researchers sought to determine energy loss points and determine energy savings potentials.

Investigating efficiency of selected compressor stations along the three pipelines showed it to be lower than designed. Some stations with 10-25 Mw gas turbines installed were producing <4 Mw, prompting a 3-year study to determine energy loss by each station component. Investigating turbine efficiency showed that only

COMPRESSOR THERMAL EFFICIENCY

FIG. 2



Siemens turbines closely approximated to design operations.Other turbines had lower performance in most cases (Fig. 2).

Turbines lose most of their power through the exhaust system. Investigation showed Siemens turbines losing less than others through this path.

Compressors

Investigating compressors revealed the following characteristics:

:: Compressor 260-13-1. Installed in old Russian stations, real power consumption was higher than designed power consumption by 400-1,000 kw, growing as rpm's increased.

:: Compressor PCL 802-3. Operates with Nuovo Pignone turbo compressors. Power consumption was 400-1,000 kw higher than designed and efficiency 5-10% lower.

:: Compressor BCL 605. Also uses Nuovo Pignone turbo compressors. Power consumption is 200-1,300 kw higher than designed and the difference between designed polytrophic efficiency and operational efficiency 5-9%.

:: Simner-design compressors. Used 0.5-1.5 Mw more power than designed. Operational efficiency in Sinner-design E compressors was 5-7% lower than designed polytrophic efficiency in most instances.

Scrubbers

Scrubbers are responsible for nearly 10% of compressor stations' energy loss. More than 40% of scrubbers were dirty (resulting in a 10-25 psi pressure drop) and nearly 10% were completely out of commission (resulting in >25 psi pressure drop). Pressure drop under optimum conditions is 5-10 psi.

Air coolers

Aspen-HTFS+ software-based simulation compared air cooler function with design parameters.

Researchers used designed gas flow conditions to compare air cooler efficiency with international standards. The actual pressure drop of 9.6 psi exceeded expectations of 8.5 psi.

Tested air coolers had a hairpin arrangement, with total output gas of the turbocompressor flowing into a common header and then being divided between air coolers by an input header before entering transformer tubes. Other air coolers have a straight arrangement, with total output gas of each turbocompressor directly entering an air cooler bank.

Pressure drops more rapidly in a straight configuration. Researchers found a 14.3 psi pressure drop in straight-designed air coolers. Using hairpin air coolers reduces pressure drop, decreasing gas consumption. Table 6 shows the effects of a reduced pressure loss in hairpin air coolers. Optimizing air cooler design in a straight arrangement reduces pressure loss even further (Table 7).

HAIRPIN COOLER-DESIGN EFFECTS — Table 6

	Status quo	Optimum cooler design
Input gas flow, MMscfd	100	100
Outlet gas pressure leaving origin station, psi	1,000	1,000
Pressure drop in air coolers, %	9.6	1.5
Gas pressure in downstream station inlet, psi	780	789.7
Downstream station compressor power consumption, kw	34,875	33,043
Downstream station compressor power consumption decrease, kw	1,833	
Equivalent annual natural gas saving under optimum design conditions, cu m	5,017,199	

STRAIGHT COOLER-DESIGN EFFECTS — Table 7

	Status quo	Optimum cooler design
Input gas flow, MMscfd	100	100
Outlet gas pressure leaving origin station, psi	1,000	1,000
Pressure drop in air coolers, %	14.5	1.4
Gas pressure in downstream station inlet, psi	808	823.7
Downstream station compressor power consumption, kw	29,672	26,867
Downstream station compressor power consumption decrease, kw	2,805	
Equivalent annual natural gas savings using optimum design, cu m	7,678,365	

Savings potential

Identifying energy loss points allowed definition of potential savings and recovery. Energy savings possibilities included reducing:

:: Energy loss from scrubber pressure drop.

:: Energy loss from air cooler pressure drop.

:: Electrical energy consumption in air coolers.

STATION COMPARISON Table 8

Station type	Thermal efficiency, %	Power loss through chimney, kw
Nevskey	20.37	44,450
Zorya	18.73	40,975
Nuovo Pignone	21.13	49,210
Siemens	29.30	27,220
Optimum design	40	

Potential energy recovery lay in reducing energy leaving compressor stations through the chimney. Energy captured by reducing pressure drop can be applied to transmission instead.

Table 8 shows the two parameters used in calculating energy savings and thermal recovery values.

Energy lost through a station's chimney reduces gas turbine thermal efficiency. Studying the polytrophic efficiency and consumption power of compressors also showed potential to save large volumes of fuel gas (Table 9).

COMPRESSOR COMPARISON Table 9

Compressor	Polytrophic efficiency, %		Consumed power, Mw	
	Operational avg.	Design avg.	Operational avg.	Design avg.
Siemens	70.15	76.65	10.53	9.54
BCL605	68	74.9	17.3	16.3
PCL802-3	71.3	78.6	7.9	7.2
260-13-1	—	—	4.5	3.9

SCRUBBER PERFORMANCE Table 10

Station	Clean, 0-10 psi, %	Dirty, 10-25 psi, %	Out of allowable range, 25-100 psi, %
No. 1	48	37.3	14/7
No. 2	31.1	46.4	22.5
No. 3	24.5	41.3	34.2
No. 4	15.2	57.1	27.7

Table 10 shows scrubber performance.

Energy consumption

This article initially outlined existing energy consumption norms in gas pipelines and describED essential parameters and criteria for comparing operational conditions with design conditions and optimum conditions. It then discussed the potential energy savings found in each compressor station component. It will now turn to available means for realizing these savings and an economic analysis of the results.

Gas turbines

Methods for energy savings and recovery in compressor stations' gas turbines include:

:: Using a recuperator.

Air entering a combustion chamber is preheated by hot air leaving the turbine and entering a recuperator. This system, however, is suitable only for gas turbines with low power and low pressure ratios. High-pressure turbines suffer from low efficiency when using a recuperator since the pressure loss is greater. Recuperators could only operate at those Iranian compressor stations using Nevsky systems.

:: Cooling the input air.

:: Recovering energy lost through the chimney.

:: Replacing the gas turbine.

Inlet air

Practical methods for cooling a compressor station's inlet air include:

:: Direct evaporation system.

:: Absorption, mechanical chillers.

:: Underground channels.

POWER REQUIREMENTS OF SIEMENS COMPRESSOR, KW Table 11

Cooling type	Chiller	FOG system	Underground channel	Underground channel, FOG	Underground channel, chiller
Ambient, 35° C.	20,097	20,097	20,097	20,097	20,097
29° C.			21,252		
27° C.		21,559			
21° C.				23,407	
15° C.	23,100				23,100
Outlet power increase	3,003	1,462	1,155	3,310	3,003
Consumed power	1,200	17	100	117	820
Net outlet power	1,803	1,445	1,055	3,193	183

Table 11 summarizes the effects of each on Siemens compressors.

Cooling the inlet air has a negligible effect on system efficiency, and is suggested only for stations facing operational limitations in hot months of the year.

In-chimney recovery

Either a Kalian cycle or organic Rankine cycle (ORC) chimney unit can recover energy from the chimney.

KALIAN CYCLE EFFICIENCY, NEVSKY UNITS Table 12

Turbine outlet power, kw	874.1
Net system outlet power, kw	853.5
System efficiency, %	14.52
Gas turbine efficiency under design conditions, %	28
Gas turbine efficiency equipped with Kalian system, %	30

:: Kalian cycle is useful when the exhaust-gas temperature from the chimney is low, limiting possible energy recycling. In Iran such conditions occur only when using Nevsky gas turbines. Since these turbines have very low efficiency, however, they are not good candidates for energy recycling equipment and should instead be replaced by higher-efficiency turbines.

Table 12 summarizes Kalian cycle's effect on Nevsky units under design conditions. The authors do not recommend their use. ORC cycle is the best energy recovery solution. Fluid selection is based on gas turbine conditions, local conditions, and the technology used by the manufacturer. But average ORC cycle efficiency at compressor station chimney temperature is about 10%. The low temperature in Nevsky gas turbine chimneys, however, precludes use of the ORC cycle on efficiency grounds.

Calculations show recoverable power in compressor stations using ORC cycles of about 120 kw/hr. Since the recovered energy in the ORC cycle is electrical and electric energy use in compression stations is low, the saved electric energy is best used to start another gas compressor by electric motor.

Turbine replacement

Gas turbines normally operate at lower efficiency than their design condition. Reconstructing compressor stations and replacing gas turbines can increase thermal efficiency. This article considers two turbine replacement scenarios. Table 13 shows energy savings stemming from replacing existing turbines with units having 40% better thermal efficiency. In the second scenario, Siemens turbines replace the

TURBINE REPLACEMENT, 40% THERMAL EFFICIENCY — Table 13

Station	Gas savings, million cu m/year
No. 1	95
No. 2	76
No. 3	93
No. 4	48
No. 5	100

TURBINE REPLACEMENT, WITH SIEMENS — Table 14

Station	Gas savings, million cu m/year
No. 1	46
No. 2	31
No. 3	47
No. 4	3
No. 5	50

INITIAL COOLER DESIGN PARAMETERS — Table 15

Gas outlet temp., °C.	15
Pressure drop caused by air cooler, psi	9.5
Cost, $	9,183,981

existing units, resulting in the energy savings shown in Table 14.

Feed cooling

Cooling a compressor station's gas feed can decrease its power requirement. Either a chiller or an air cooler can cool the gas feed. Preliminary calculations show a chiller uses too much energy to be economical. Table 15 shows general specifications of an air cooler used in cooling a compressor station's gas feed.

ANNUAL SAVINGS, AMBIENT TEMP. BELOW GAS FEED Table 16

Compressor power requirement drop, kw	6,250
Station fuel consumption drop, million cu m	2.44

SAVINGS, COST COMPARISON Table 17

Station	Fuel consumption decrease potential, million cu m/year	Overall cost, $	Annual cost, $
No. 1	1.1	5,013,213	251,000
No. 2	4.3	8,059,140	536,775
No. 3	5.9	8,693,586	816,680
No. 4	3.7	11,018,083	616,260
No. 5	3.3	8,254,959	397,550

Table 16 shows the reduced power needs and fuel requirement realized by using an air cooler for a year, given that the ambient temperature is cooler than the gas feed. Table 17 shows the cost savings potential achieved by using air coolers at five other stations in differing climates.

SHAGHAYEGH KHALAJI is a senior expert of energy management at National Iranian Gas Co. She earned an MS in chemical engineering (2002) from Tehran University.

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COMPRESSOR OPTIMIZATION—2 (Conclusion): Energy recovery, scrubbers offer keys to efficient operation

by **SHAGHAYEGH KHALAJI**

ENERGY RECOVERY AND efficient scrubber technologies can help minimize energy loss on natural gas transmission systems.

Iran's natural gas pipeline system requires roughly 60% more power/unit shipped than the global average. Iranian gas does not have to travel particularly long distances, but its compressor units are of relatively low efficiency and the booster compressor stations somewhat underpowered. The system's design also occurred when domestic gas prices in Iran were very low, reducing the emphasis placed on efficiency.

The first article of this series (OGJ, Jan. 9, 2012, p. 104) outlined existing energy consumption norms in gas pipelines, describing essential parameters and criteria for comparing operational conditions with design conditions and optimum conditions. This concluding article will focus on the effect of scrubbers and other equipment in attempting to maximize capital return.

Gas turbines normally work at lower efficiency than their design condition. Reconstructing compressor stations and replacing gas turbines can increase thermal efficiency. Lost heat can be recovered to generate electricity via a Rankine power cycle. Turboexpanders can use reduction in gas pressure to generate power.

Cooling a compressor station's gas feed, meanwhile, can decrease its power requirement. Either a chiller or an air cooler can cool the gas feed. Inlet air cooling can prevent loss of output when ambient temperatures are high. Preliminary calculations, however, showed a chiller uses too much energy to be economical.

After investigation determined energy loss levels, potentials for mitigating this loss or recovering the lost energy were defined. Energy saving possibilities included reducing:

:: Energy loss from scrubber pressure drop.

:: Energy loss from air cooler pressure drop.

:: Electrical energy consumption in air coolers.

Scrubbers

Scrubbers help separate excess liquids or undesirable particles from the gas stream as it passes through a compressor station, keeping the stream properly dehydrated.

Scrubber performance is best improved through:

:: Redesign, replacement.

:: Timely replacement of filters.

As mentioned in the first article of this series, scrubber pressure drop can sometimes exceed 25 psi. This scale of pressure drop requires either scrubber replacement or use of a new scrubber in parallel with the existing one. Calculations show gas savings when scrubber performance was optimized of 6.1 million cu m/year.

Table 1 shows five test stations' gas savings achieved via scrubber optimization. Savings are based on the unit's average thermal efficiency and 1,388 working hr/year (Mar. 21, 2009-Mar. 20, 2010).

SCRUBBER OPTIMIZATION SAVINGS Table 1

Station	Gas savings, million cu m/year
No. 1	3.3
No. 2	3.4
No. 3	4.5
No. 4	2.4
No. 5	6.8

Air coolers

Both redesign and replacement and a simple bypass of air coolers can reduce gas consumption. Table 2 shows the volumes of gas saved optimizing air cooler performance under average working conditions.

When ambient conditions are cool enough, the temperature of gas leaving the compressor may be low enough to enter the transfer line without first being cooled, eliminating air cooler pressure drop. Table 3 shows gas savings associated with bypassing the air cooler.

GAS SAVINGS, OPTIMIZED AIR-COOLER PERFORMANCE Table 2

Station	Potential savings, million cu m/year
No. 1	3.72
No. 2	0.89
No. 3	1.68
No. 4	1.63
No. 5	0.7
No. 6	2.02
No. 7	2.26
No. 8	1.67

GAS SAVINGS, AIR-COOLER BYPASS Table 3

Station	Gas savings, million cu m/year
No. 1	1.07
No. 2	0.31
No. 3	0.32
No. 4	0.42
No. 5	0.22
No. 6	0.59
No. 7	0.59
No. 8	0.58

Turboexpanders can also reduce the amount of gas required to do the same quantity of work. Tables 4, 5, and 6 show the savings realized by this approach, respectively showing power use when outlet-gas temperature is the same as ambient temperature, when outlet-gas temperature is cooled as much as possible, and when inlet gas is preheated.

Economic analysis

Energy optimization requires advantages and costs to be reported and assessed in financial terms. The indices such assessments use are:

- Cash flow (Equation 1).
- Internal rate of return (Equation 2).
- Capital return time (Equation 3).
- Net present value of investment (Equation 4).

STATION PERFORMANCE, OUTLET GAS TEMPERATURE SAME AS AMBIENT

Table 4

Station capacity, cu m/hr	<10,000	10,000-50,000	50,000-100,000	100,000-200,000	200,000-500,000	500,000-1 million
Average throughput, cu m/hr	9,000	37,000	72,380	139,730	371,000	866,000
Average power production, Mw	0.20	0.81	1.59	3.07	8.16	19.04
Heat demand, Mw	0.249	1.02	2.00	3.86	10.25	23.92

STATION PERFORMANCE, MAXIMUM OUTLET GAS COOLING

Table 5

Station capacity, cu m/hr	<10,000	10,000-50,000	50,000-100,000	100,000-200,000	200,000-500,000	500,000-1 million
Average throughput, cu m/hr	9,000	37,000	72,380	139,730	371,000	866,000
Average power production, Mw	0.18	0.76	1.48	2.86	7.6	17.74
Heat demand, Mw	0.14	0.57	1.11	2.14	5.67	13.24

STATION PERFORMANCE, PREHEATED INLET GAS

Table 6

Station capacity, cu m/hr	<10,000	10,000-50,000	50,000-100,000	100,000-200,000	200,000-500,000	500,000-1 million
Average throughput, cu m/hr	9,000	37,000	72,380	139,730	371,000	866,000
Average power production, Mw	0.22	0.912	1.78	3.44	9.15	21.35
Heat demand, Mw	0.43	1.75	3.43	6.63	17.60	41.07

Assumptions

The external parameters used in calculating project economics include:

:: Expenses and incomes set at 2010-11 levels.

:: Real interest rate for net value calculation of 5%.

:: Oil price in international markets of $60/bbl, yielding a natural gas price of $0.25/cu m and a power supply price of $0.09/kw-hr.

:: Iranian thermal power plant efficiency of 35%.

:: Rankine cycle technical data yielding a design-cycle efficiency of 17.4%

Cost analysis

Five basic energy optimization solutions emerged through flow

EQUATIONS

$$CF_t = \sum_{t=0}^{t} (B_t - F_t - V_t) - I_0 \quad (1)$$

where:

CF_1 = Cash flow

B_t = Profits during time = t at fixed prices

V_t = Annual variable costs during time = t at fixed prices

I_0 = Basic and capital requirements

$$\sum_{t=0}^{t} \frac{(B_t - F_t - V_T)}{(1 + IRR_t)^t} - I_0 = 2 \quad (2)$$

where:

IRR_t = Internal return rate of capital during t

B_t = Advantages resulting from the project during t at fixed prices

F_1 = Annual fixed expenses during t at fixed prices

V_t = Annual variable expenses during t at fixed prices

I_0 = Initial expenses and capital requirement

$$\sum_{t=0}^{t} \frac{(B_t - F_t - V_t)}{(1 + r_t)^t} - I_0 = 0 \quad (3)$$

where:

t = Capital return time

r_t = Capital interest rate during t

B_t = Profits resulting from the project during t at fixed prices

F_t = Fixed expenses during t at fixed prices

V_t = Annual variable expenses during t at fixed prices

I_0 = Initial expenses and capital requirement

$$\sum_{t=0}^{t} \frac{(B_t - F_t - V_t)}{(1 + r_t)^t} - I_0 = NPV_t \quad (4)$$

where:

NPV_t = Net present value of the investment during t

r_t = Capital interest rate during t

B_t = Profits resulting from the project during t at fixed prices

F_t = Fixed expenses during t at fixed prices

V_t = Annual variable expenses during t at fixed prices

I_0 = Initial expenses and capital requirement process study at the sample compressor stations:

:: Heat recovery from chimney gases and electric power production.

:: Gas turbine reconstruction.

:: Cooling natural gas feed.

:: Cooling natural gas leaving compressor.

:: Scrubber optimization.

Economic investigation exposed the characteristics of each feasible solution (Table 7).

Table 8 shows the results of economic analysis of each solution using the assumptions presented earlier. Energy recovery in chimneys and its use for electric power production and scrubber optimization are economically feasible in all stations, and the return rate of the project during the exploitation term (less than 8 years) is more than 31%.

SOLUTION CHARACTERISTICS BY STATION

Table 7

Station	Heat recovery system, Organic Rankine Cycle Gw-hr/yr	Renovated gas turbine Million cu m/yr	Renovated gas turbine $, thousand	Natural gas cooling Million cu m/yr	Natural gas cooling $, thousand	Air cooling Million cu m/yr	Air cooling $, thousand	Scrubber Million cu m/yr	Scrubber $, thousand
No. 1	119	49	25,000	—	—	3.72	3,710	2.7	700
No. 2	25	—	—	1.07	—	0.89	3,200	0.6	350
No. 3	—	10	25,000	1	1,834	—	—	1.4	700
No. 4	64	26	25,000	1.65	3,079	1.68	2,300	1.2	350
No. 5	40	—	—	1.63	3,146	1.63	2,877	0.8	350
No. 6	—	10	25,000	1.46	1,834	—	—	1.7	700
No. 7	70	42	25,000	2.92	3,560	—	—	1.9	700
No. 8	35	—	—-	1.54	3,299	0.68	2,050	0.9	350
No. 9	72	—	—	2.44	9,184	2.02	2,966	1.1	350
No. 10	—	12	25,000	0.75	1,780	—	—	2.8	700
No. 11	99	41	25,000	1.69	3,329	2.26	2,410	3.2	1,050
No. 12	26	—	—	0.9	3,146	1.67	2,266	0.9	350

SOLUTION RESULTS BY STATION

Table 8

Station	Heat recovery system, ORC: Capital, $1,000	Mw	Internal rate of return, %	Net present value, $	Gas turbine replacement GT 10 B: IRR, %	NPV, $	Gas cooling: IRR, %	NPV, $	Air cooling: IRR, %	NPV, $	Scrubbers: IRR, %	NPV, $
No. 1	25,040	17.0	29	33,871	41	44,095	—	—	14	1,523	91	3,678
No. 2	5,261	3.6	29	7,116	—	—	—	—	—	—	36	566
No. 3	—	—	—	—	—	—	—	—	—	—	43	1,472
No. 4	13,467	9.1	29	18,216	13	8,610	—	—	—	—	36	1,132
No. 5	8,417	5.7	29	11,385	—	—	—	—	—	—	51	906
No. 6	—	—	—	—	—	—	6	110	—	—	55	1,981
No. 7	14,730	10.0	29	19,924	33	33,295	7	359	—	—	62	2,320
No. 8	7,365	5.0	29	9,962	—	—	—	—	—	—	59	1,075
No. 9	15,150	10.3	29	20,493	—	—	—	—	—	—	31	963
No. 10	—	—	—	—	—	—	—	—	—	—	95	3,847
No. 11	20,832	14.1	29	28,178	32	31,752	—	—	12	724	109	4,526
No. 12	5,471	3.7	29	7,400	—	—	—	—	—	—	59	1,075

Scrubber optimization is the best approach, significantly lowering costs and energy consumption in natural gas transfer lines. Cooling natural gas before and after compressors is justifiable in some stations, and gas turbine reconstruction and replacement is justifiable in older, less efficient units.

Cost-benefit analysis

Energy is gradually lost in gas pressure reduction stations, dissipating the mechanical work potential produced by compressors. The recovery of mechanical potential and its transformation into work and the production of electric energy is, therefore, a suitable mechanism for energy optimization in a natural gas system.

Table 9 contains expansion turbine data for both small (less than 10,000 cu m/hr normal gas flow) and large units (500,000 to 1 million cu m/hr normal gas flow).

EXPANSION TURBINE DATA Table 9

Gas flow <10,000 cu m/hr		
Power capacity	Mw	0.2
Heat demand	Mw	0.25
Capital costs	$/kw	950
Gas flow: 500,000 to 1 million cu m/hr		
Power capacity	Mw	20
Heat demand	Mw	25
Capital costs	$/kw	650

Table 10 shows economic analyses based on $60/bbl crude oil. The internal return rate in a 4-year exploitation period will be more than 26%/year. The

ECONOMIC ANALYSIS, $60/BBL CRUDE Table 10

Years of operations		–1	0	1	2	3	4	5	6	7	8
Gas flow <10,000 cu m/hr											
Capacity	Mw	—	0.2	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Cash flow	$1,000	–190	72	72	72	72	72	72	72	72	72
IRR	%/year	—	—	–17	7	19	26	30	33	34	36
NPV	$1,000	—	–115	–53	6	63	117	168	217	263	308
Gas flow, 500,000 to 1 million cu m/hr											
Capacity	Mw	—	20	0	20	20	20	20	20	20	20
Cash flow	$1,000	—	7,519	7,519	7,519	7,519	7,519	7,519	7,519	7,519	7,519
IRR	%/year	—	–42	10	34	45	50	53	55	56	57
NPV	$1,000	—	–5,561	933	7,119	13,010	18,620	23,964	29,053	33,899	38,515

ECONOMIC ANALYSIS, VARIABLE CRUDE PRICES Table 11

	Gas savings, million cu m/year	Savings, $ million	Years	IRR, %					NPV, $				
Oil price, $/bbl	—	—	—	10	25	50	65	80	10	25	50	65	80
ORC cycle, electric gas compressor	44	27.089	10	–7	5	20	28	35	–12,513	579	22,400	35,492	48,584
Gas turbine, 40% efficiency	85	—	—	—	—	—	—	—	—	—	—	—	—
Siemens gas turbine	49	25	10	–23	5	32	46	59	–18,904	–4	31,495	50,395	62,294
Air cooler in station inlet	—	—	—	—	—	—	—	—	—	—	—	—	—
Optimized scrubber	2.7	0.7	10	0	32	75	100	124	–140	1,005	2,914	4,059	5,205
Optimized air cooler	3.72	3.7	10	–	12	8	17	25	–3,737	–2,159	471	2,049	3,627
Bypass route	1.07	—	—	—	—	—	—	—	—	—	—	—	—

present value of the investment in a small system for the 4-year exploitation period will be $117,000 and in large systems $18.62 million. Mechanical recovery is economically justifiable and provides a basic solution for energy recycling in compressor stations.

Solution prioritization

As shown in Part 1, only Organic Rankine cycle for energy recovery and optimization of scrubbers are economically feasible in all instances, the rest of the solutions being viable only in particular situations.

Table 11 shows detailed economic analyses for sample stations using five different crude prices.

SHAGHAYEGH KHALAJI is a senior expert of energy management at National Iranian Gas Co. She earned an MS in chemical engineering (2002) from Tehran University.

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Analysis yields turnaround benchmarks for allowance, contingency

by **GORDON LAWRENCE**

TURNAROUNDS—ALSO KNOWN AS planned outages or shutdowns—are major events for refineries and other petrochemical facilities. They typically cost large sums of money to execute. Cost estimates for turnarounds, however, have historically been rather inaccurate. This can often be traced to an inability accurately to calculate allowances and contingency for "unknowns" in the estimate.

This article examines the allowances and contingencies that are needed, the different methods used for calculating them, and how much money is typically allocated and required. From this, it provides some "rule of thumb" benchmarks for turnaround estimators to use.

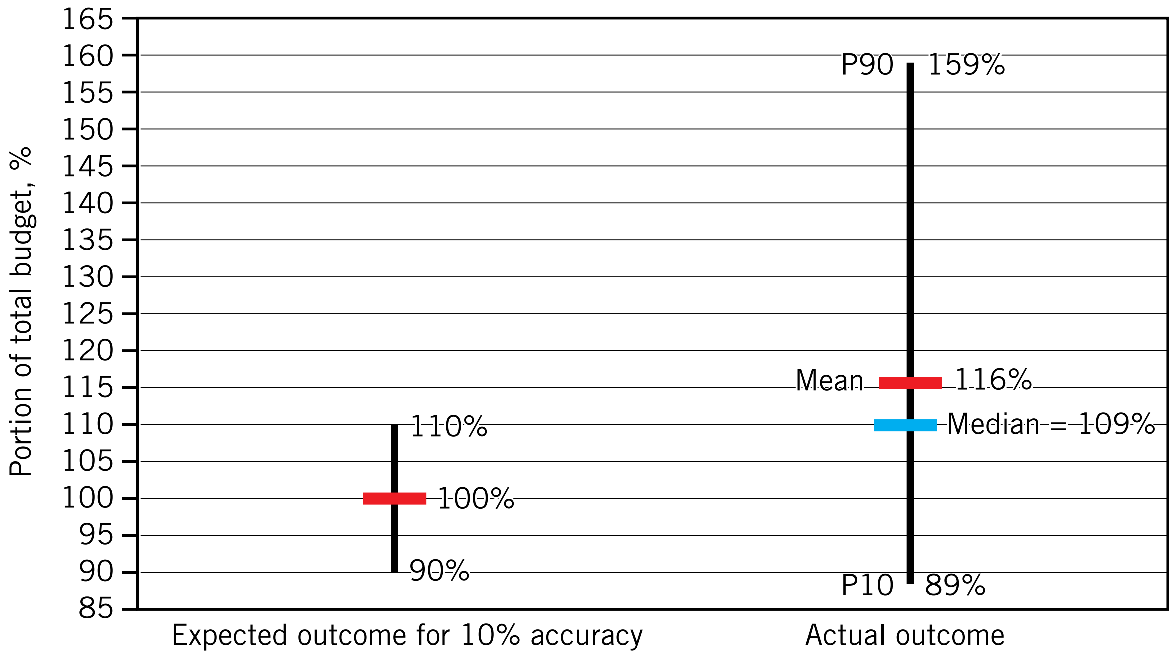
It then will discuss how the benchmarks might be refined, the advantages of tracking the use of allowances and contingencies during execution of a turnaround, and finally some recommendations for steps that estimators can take to improve their estimating capabilities for allowances and contingencies.

Turnaround estimate accuracy

As an example of how turnaround cost estimates are notoriously inaccurate. Fig. 1 shows the average budget overrun for a sample of recent turnarounds. This sample is taken from the AP-Networks turnaround database, which contains execution data on more than 750 turnarounds from almost 40 firms at plants worldwide. It includes schedule data, execution information, and scope characteristic data, as well as the cost data referred to here.[1]

ACTUAL TURNAROUND COST

FIG. 1



From this sample we can see that turnarounds typically overrun their estimates by an average value of 16%. Furthermore, the variability around that average is on the order of –27% to +43%, which is far wider than the ±10% at 80% confidence that most turnaround teams claim to be their estimate-accuracy level.

The reasons for this weakness in estimating can partly be explained by a lack of knowledge among owner companies' estimators as to how much money to allow in the estimate for the unknowns in their turnaround scope.

What are 'unknowns'?

Any turnaround will include a maintenance scope, consisting of:

- Inspection of equipment to company regulations or government mandatory rules.
- Inspection of pipework for corrosion and erosion damage, both internal (for example, process weak points) and external (for example, corrosion under insulation, or CUI).
- Cleaning, repair, and maintenance of equipment, pipework, and instrumentation (for example, pulling and cleaning heat exchanger tube

bundles, repairing leaks in pipework, or checking of pressure-relief valves).

- Minor upgrades and modifications to the plants (items controlled under the "management of change" procedures).

Most turnarounds will also include a project scope, consisting of tie-ins (for future capital projects) that can only be installed when the plant is shutdown.

The scope of both maintenance and project that is known at the time of "scope freeze" can generally be estimated by the turnaround estimator, based on historical knowledge. Scope freeze is the date set by the team, by which time all interested parties—inspection department, plant operators, project teams, so forth—are to have offered all tasks they would like included in the turnaround. Those tasks have been challenged and accepted as being unable to be done during normal operations. This typically occurs around 9 months before the shutdown.

Problems arise, however, with allowing for unknowns. These consist of the additional work that inevitably creeps into the scope after the scope freeze date and the costs that grow beyond the original estimate, due to underestimation of quantities, optimistic estimation of productivity, changes in material costs, and so forth.

The unknowns are typically covered by turnaround estimators by their including in the estimate some kind of allowance or contingency funds. Some estimators simply include a single line item to cover all allowance and contingency eventualities. The likely areas needing to draw from that fund, however, will fall into one of four categories:

- *Forgotten, overlooked work*. This is work known before the scope freeze date but which, for whatever reason, was not included in the basis of estimate.
- *Emerging work*. This is work arising from equipment that breaks down or pipework that leaks after the scope freeze but before the start of the shutdown for the turnaround.
- *Discovery work*. This is work that was unknown (or only suspected) at the time of scope freeze, which could not be verified because access is impossible while the plant is running and which is only discovered when equipment or pipework is opened during the shutdown.

:: *True contingency.* This refers to additional funds for items that simply end up costing more than originally allowed for in the estimate or for completely unexpected activities.

The categories of forgotten, overlooked, and emerging work are usually lumped together by turnaround estimators. This combined category is then typically known simply as either emerging work or additional work.

Calculating allowances, contingency

The problem for the estimators is how much money to include as allowance or contingency. There are effectively four basic methods for calculation:

:: Using a predetermined percentage.

:: Using expert judgment.

:: Using a probabilistic risk analysis method such as Monte Carlo simulation.

:: Using a regression model.

We can consider how each of these might be employed by a turnaround estimator.

Predetermined percentages can be a good "rough-and-ready" way of calculating contingency. But the issue always arises that, in order to know what the percentage should be, one needs some benchmark of what was needed in the past.

Using the "gut-feel" judgment of an expert can also be a good "rough-and-ready" way of calculating contingency. But, of course, one first needs the expert. Recent history of turnaround cost outcomes suggests that these experts are few and far between for turnarounds.

Probabilistic risk analysis uses a Monte Carlo simulation or similar method to calculate the contingency requirement and estimate range.

At first glance, Monte Carlo appears to offer the most scientific and by extension the most accurate method for calculating allowances and contingency. One study, however, casts some doubt on that assumption.[2] It study looked at Monte Carlo in comparison to the other three methods discussed here. It focused on capital project estimates and therefore may not be fully transferable to turnaround estimates; nevertheless, its findings are instructive.

It was discovered that, contrary to general perceptions in the industry, for early estimates predetermined percentages and especially expert judgment provided results that were generally much better than the results from the supposedly more rigorous Monte Carlo method. Monte Carlo did provide better results for very detailed estimates, but the advantage it gave over predetermined percentages and expert judgment was slight.

The referenced article does not discuss in detail why Monte Carlo does not provide the expected superior results to the other methods, but it seems reasonable to assume that part of the reason is that Monte Carlo analysis is not always carried out with sufficient rigor and skill. The study looks at whether Monte Carlo was used, not whether Monte Carlo was used correctly.

A proper Monte Carlo analysis requires a well facilitated session to identify, analyze, and evaluate the risks and uncertainties in scope and estimate. That session in turn, requires sufficient detail in the estimate to allow the risks to be identified. It also requires the team to abandon the usual over-optimism that prevails in most discussions of contingency requirements.

Monte Carlo therefore may well be useful for contingency setting but only if used with sufficient rigor. Since most turnaround teams lack the skills and training in-house, they would need to look externally for support to implement this method successfully.

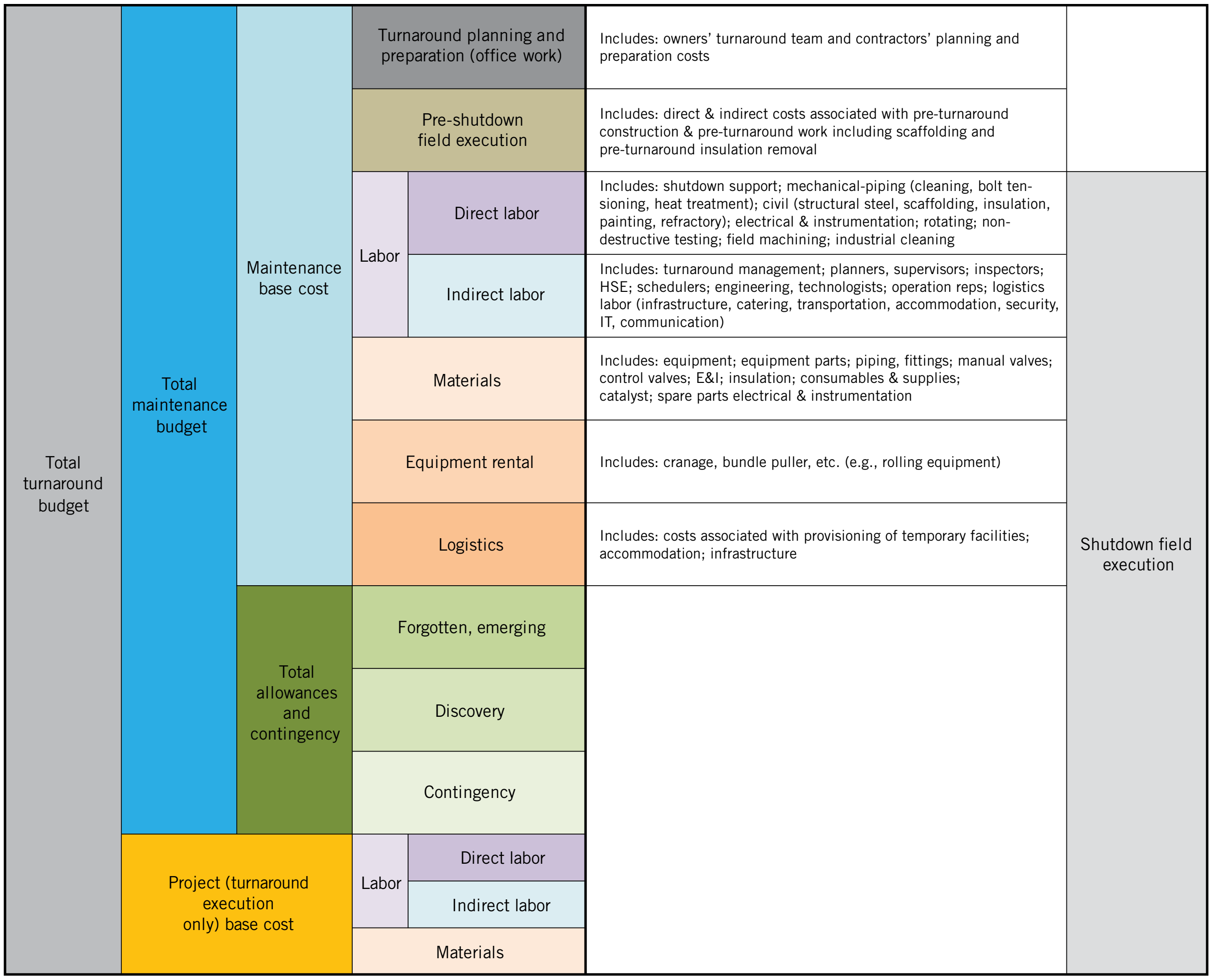
Developing a regression model can be a relatively accurate method for calculating contingency requirements, but it requires a large data set on which to build the model. Most owner-company estimators do not have such a data set available to them.

Benchmarks for allowances, contingency

What follows are some benchmark data that could be used by owners' cost estimators as rules-of-thumb in applying the predetermined-percentage method or the expert-judgment method to their turnaround cost estimates.

ELEMENTS OF COST ESTIMATE

FIG. 2



These benchmarks present the allowances and contingency as percentages of elements of the turnaround's cost estimate. Understanding them requires being clear about what is meant when we talk about an element of "the cost estimate."

We have used the definitions as laid out in Fig. 2. The benchmarks are generally shown as percentages of one of the following:

:: The total maintenance and project base cost (i.e., excluding allowances and contingency).

:: The total maintenance base cost.

:: The total maintenance budget.

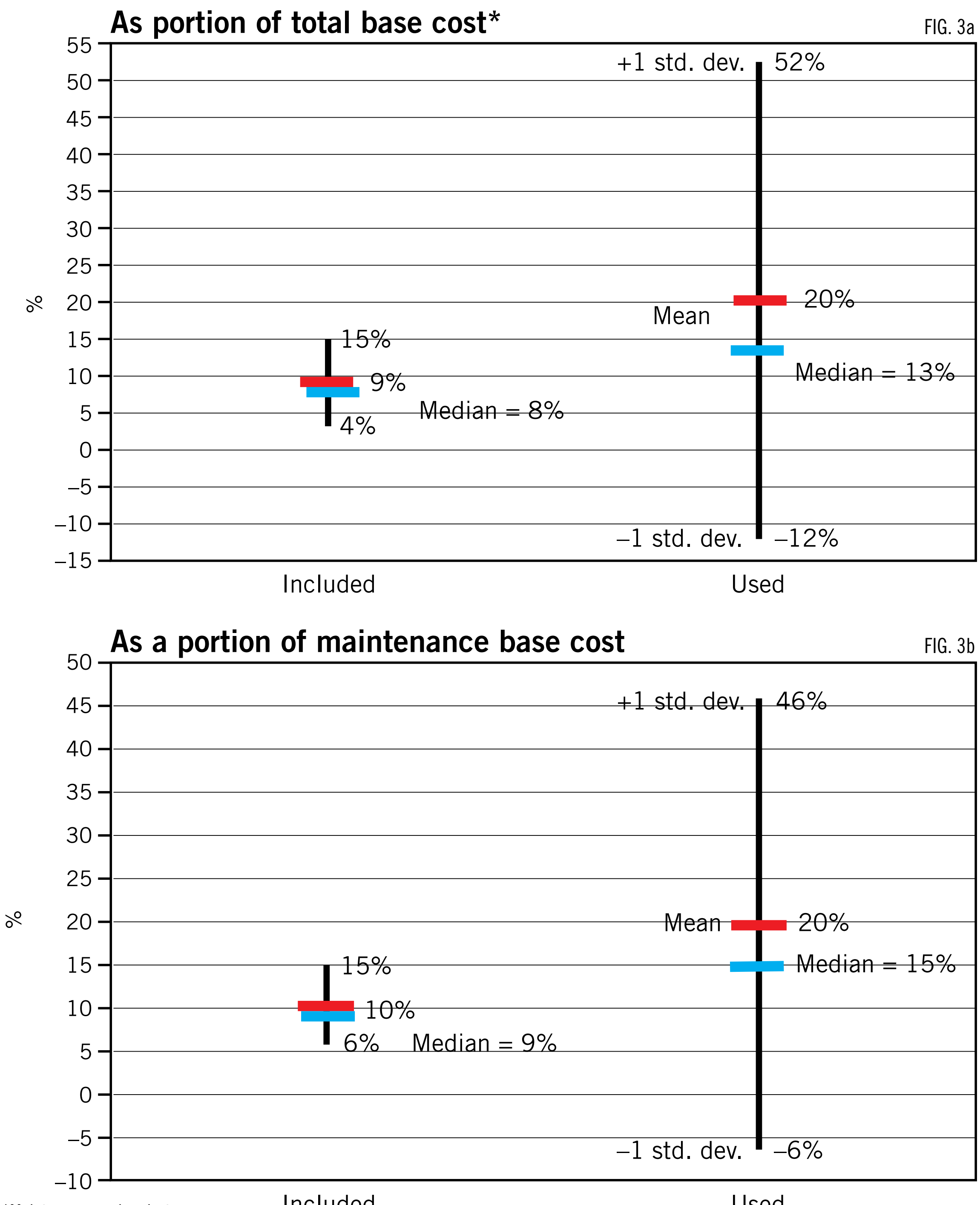
The data sets used to calculate the benchmarks are drawn from the AP-Networks turnaround database mentioned earlier.

Allowances, contingency as a block value

These two benchmarks (Fig. 3) show the total allowances and contingency (i.e., forgotten work + emerging work + discovery work + true contingency) as one block, in comparison with different elements of the turnaround budget.

TOTAL ALLOWANCE, CONTINGENCY

FIG. 3



*Maintenance and projects.

:: Fig. 3a shows the total allowances and contingency as a percentage of maintenance base cost plus project base cost. Two benchmarks are given: how much teams included in their estimates and how much was actually used by those teams to complete the turnaround.

As can be seen, the teams included around 9% but actually used about 13-20%, suggesting that teams were consistently underestimating how much they would need.

In addition, the variability (the vertical line shows the standard deviation) in the value of how much was actually used, compared with the variability in the value of how much was included suggests that teams are thinking in terms of preconceived percentages that take insufficient notice of the amount of risk and uncertainty in their estimates.

Note: For those attempting to take a "back-bearing" and relate Figs. 3a and 3b to Fig. 1, bear in mind first that Fig. 1 is calculated as a percentage of total turnaround budget, whereas Figs. 3a and 3b are calculated as percentages of total base cost and of maintenance base cost, respectively. Secondly, bear in mind that Fig. 1 uses a larger data set than is used for Figs. 3a and 3b.

We were able to use a larger set for Fig. 1 because, while most turnaround teams are able to state their total budget and actual costs, far fewer teams track costs in sufficient detail to provide accurate information about the use of allowances and contingency within those totals. This in turn raises another interesting discussion point: The teams that can differentiate their allowances and contingency seem to overrun their budgets by less than the teams that cannot.

:: Fig. 3a gives a benchmark comparing the allowances and contingency to the total base cost for maintenance and projects. The amount of project involvement in a turnaround, however, can vary considerably. Therefore, in Fig. 3b, we look at total allowances and contingency as a percentage of the maintenance base cost only (i.e., without the project base cost).

Despite this change in comparison basis, the results shown in Fig. 3b remain similar to those in Fig. 3a. This time the amount included is 10%, with the used amount around 15-20%. Once again, the variability in the amount used is much greater than the variability in the amount included.

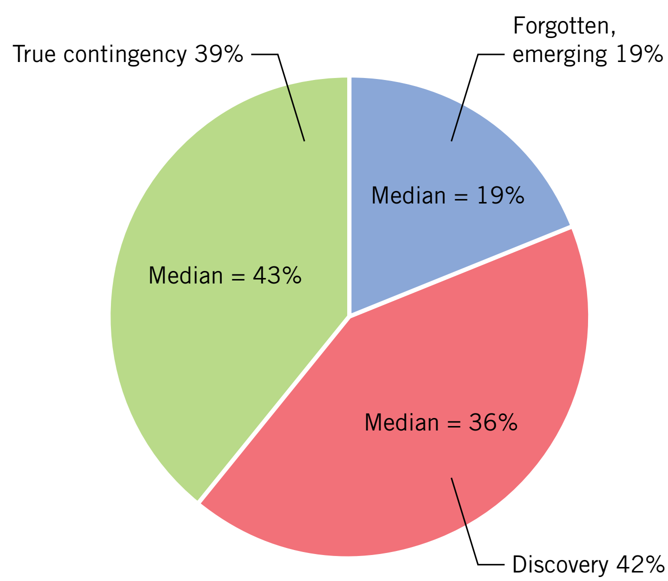
Percentage breakdown

The previous two benchmarks looked at allowances and contingency as a single unit amount. This section looks at each allowance or contingency category separately.

- Fig. 4 shows each allowance or contingency category as a percentage of the total allowances and contingency. The pie chart shows the average percentages and then the medians appear as separate notes in each pie segment. The average and the median are reasonably similar in each case, suggesting that the variability for each segment is only slightly skewed.
- Fig. 5 shows each allowance or contingency category as a percentage of the total maintenance budget (maintenance base estimate plus all allowances and contingency). Again, the mean and median are not greatly different.

TOTAL ALLOWANCE, CONTINGENCY

FIG. 4



Greater granularity

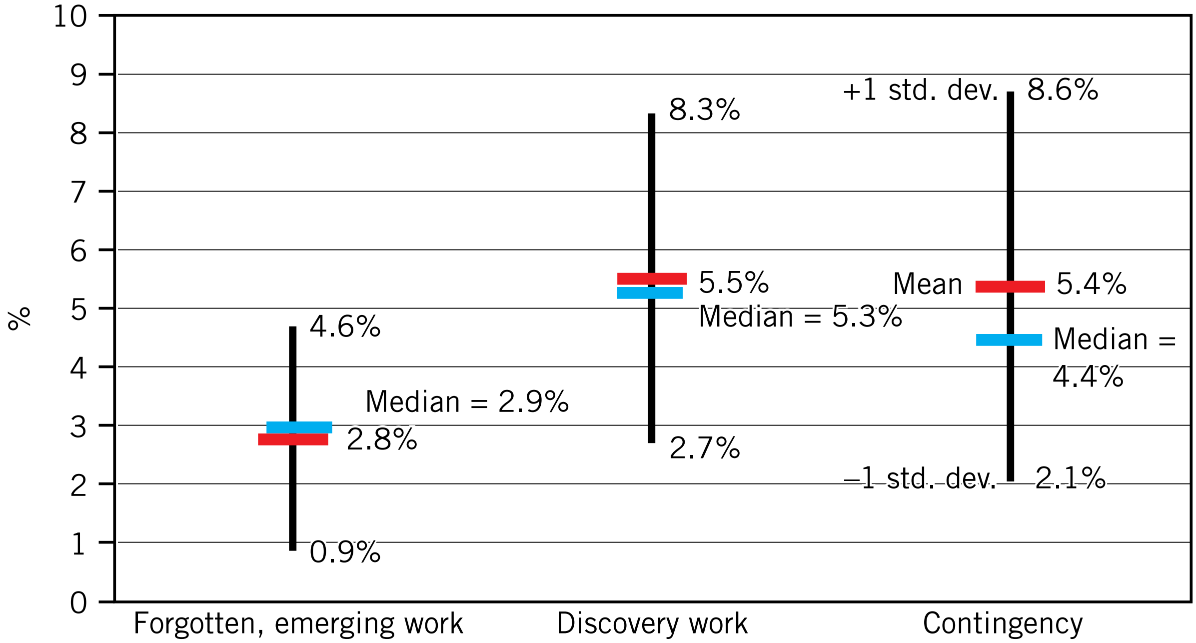
The benchmarks given in the earlier section are offered to guide turnaround estimators who have no other in-house data to begin using expert judgment or a predetermined percentage in their turnaround estimates.

These benchmarks, however, simply look at the overall average for turnarounds. From previously published research,[3 4] we are already aware that certain characteristics of a turnaround and of turnaround planning affect turnaround cost predictability. These characteristics are listed below.

Since these affect cost predictability, they will, by extension, affect the amount of allowance and contingency required. Hence a next step in providing greater granularity in the benchmarks will be to provide benchmarks that take account

ALLOWANCES, CONTINGENCY INCLUDED*

FIG. 5



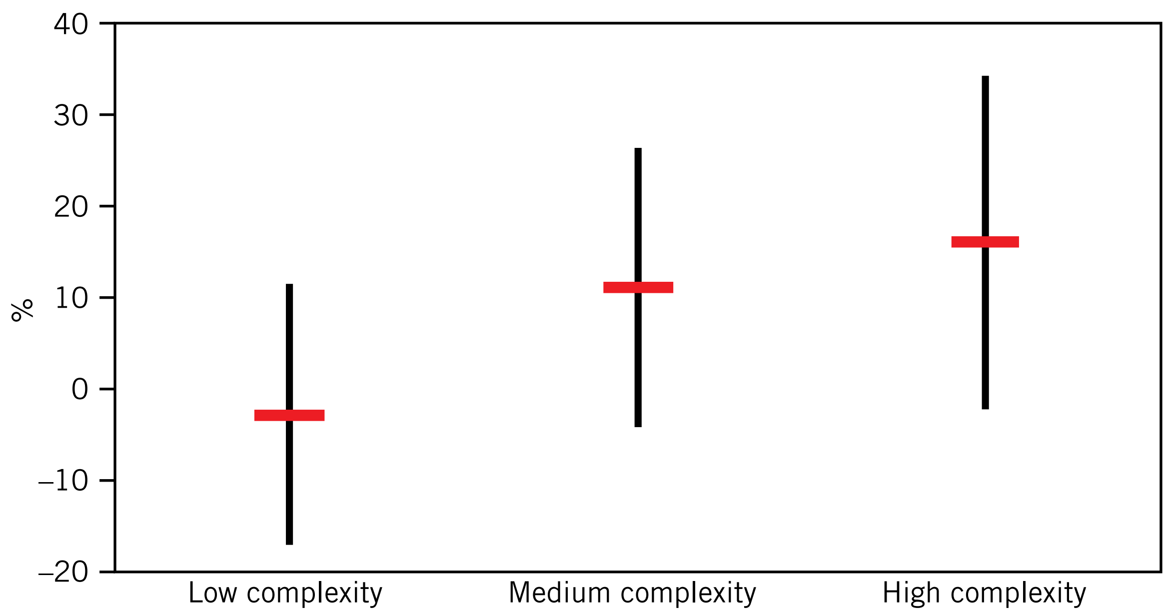
*Each category expressed as a percentage of total maintenance budget.

of these characteristics.

:: *Turnaround complexity.* For example, as shown in Fig. 6, if we examine the complexity of the turnaround (where complexity is measured as a function of

COMPLEXITY, COST OVERRUN*

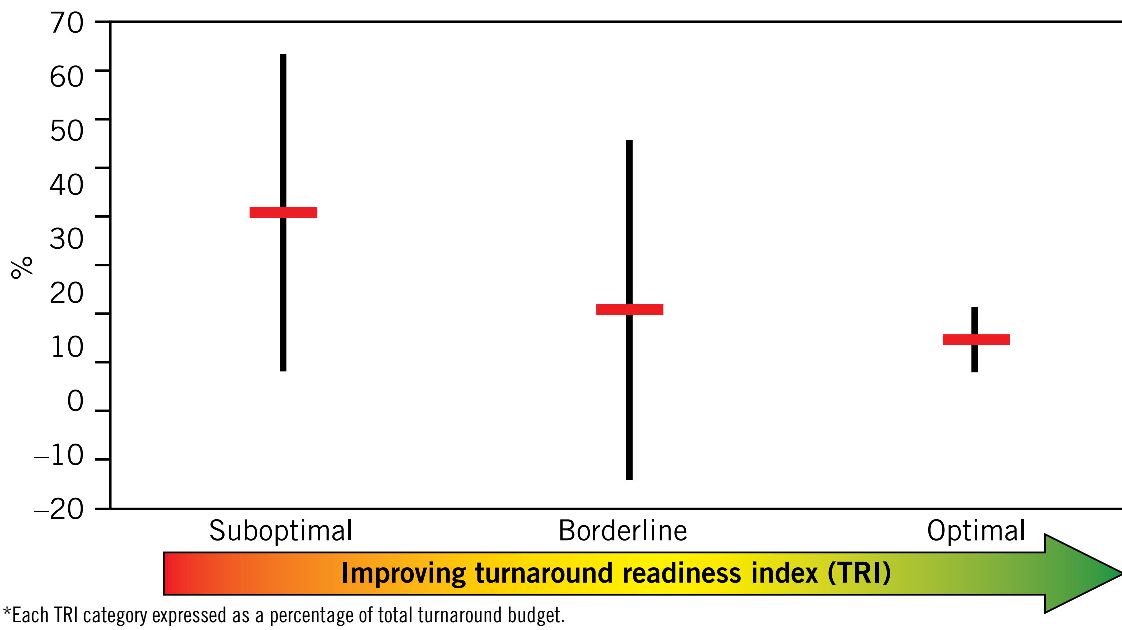
FIG. 6



*Each category expressed as percentage of total turnaround budget.
Source: Reference 4

TURNAROUND READINESS INDEX, COST OVERRUN*

FIG. 7



*Each TRI category expressed as a percentage of total turnaround budget.
Source: Reference 4

the percentage of the turnaround that involves project work, the total field-labor hours, and the interval time between turnarounds),[5] we can see that more complex turnarounds appear to overrun more (as a percentage of budget) than less complex turnarounds.

:: *Turnaround readiness.* Similarly, as shown in Fig. 7, the level of turnaround readiness (i.e., the level of planning and preparation carried out for the turnaround, before the shutdown), as measured with the AP-Networks Turnaround Readiness Index (a quantitative measure, arising from the turnaround readiness pyramid questionnaire[6]), affects cost predictability. Better prepared turnarounds unsurprisingly have fewer cost overruns.

:: *Contract strategy.* One other interesting point, raised by many turnaround teams, is whether field-labor contract payment type (e.g., unit rates, time, and materials, and so forth) affects turnaround cost predictability. One study suggests that, in comparison with complexity and readiness, contract type appears to have little to no effect on cost predictability in turnarounds.[7]

Data gathering, differentiation

Clearly, the more historical data one can gather on the use of allowances and contingencies in turnaround costs, the more benchmarks there are that can be refined. At AP-Networks, we continue to gather cost and characteristic data on every turnaround in which we are involved.

We routinely urge every turnaround team to differentiate the allowances and contingency in the estimate and clearly to track its use in the actual costs.

The cost estimator will frequently find his or her calculations challenged by management. If the estimator can produce a logical argument for how each allowance and contingency was calculated, this strengthens his or her argument for retaining the funds in the estimate.

Using benchmarks gives backing to any argument as to why a certain amount of allowance and contingency has been included. A further refinement in strengthening the argument, however, is if less of the estimate needs to be contingency, unallocated to a specific task or action. Therefore, let us examine all four categories of allowance and contingency to see whether we can better define them.

If we take each of the four categories in turn, we can see that in fact only one of the four categories, “true” contingency, really needs to be subject to a calculation technique such as expert judgment, predetermined percentage, or probabilistic risk analysis.

:: *Forgotten, overlooked work*. If a team is conducting a thorough scope-gather exercise, involving all groups with a stake in adding scope to the turnaround, then this category should ideally be zero in every estimate. Tracking its actual value will give teams a clue as to how effective are their scope gathering techniques.

:: *Emerging work*. It should be possible to estimate emerging work, based on knowledge of the reliability of the plant. For example, “We have X months between now and the shutdown. Typically, we have Y valves/month that fail. Therefore we should allow for X*Y failures in the estimate as emerging work.”

:: *Discovery work*. It should be possible to make an educated guess at discovery work, based on the operator’s knowledge of how well the plant is operating, before the shutdown. For example, “Column X is only operating at 50% of capacity; therefore, we fully expect that when we open it there will be tray damage to repair."

- *(True) contingency*. True contingency is the only category that will still need to be left to expert judgment, predetermined percentage, or probabilistic risk analysis.

Forgotten, overlooked work, emerging work, and discovery work all now become "allowances" rather than "contingency" and can be assigned to specific line items in the cost estimate. They no longer need to be amorphous buckets of money, subject to suspicion and deletion. A clear case can be made for each cost item.

Following the same reasoning, just as with capital projects, the true contingency now becomes money that, by its very nature cannot be assigned to any specific line items, but which history or experience shows will be required somewhere during execution of the project for some element of the scope that was underestimated or overlooked.[8]

This then brings turnaround estimating more in line with capital cost estimating, where, if you can assign it to a specific line item in the estimate, it's an allowance; and if you can't but historical experience tells you that you'll need the money somewhere, it's a contingency.

Looking further now makes clear that the only one of the four categories that should be affected by the presence of capital projects in the shutdown scope is true contingency, since the three allowance categories all clearly relate to the maintenance scope only. Recognizing this should also help to make the calculation and use of contingency in turnaround budgets less opaque.

AP-Networks will continue adding to its database and examining this topic, delving deeper into the variables (complexity, readiness, contract strategy, etc.) that may affect the need for allowances and contingency.

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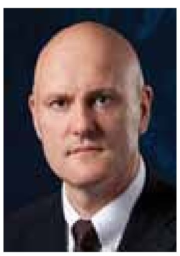

GORDON LAWRENCE (glawrence@ap-networks.com) is a senior consultant based in the Amsterdam office of Asset Performance Networks, a turnaround and capital-project consultancy. He has more than 25 years' experience in process industries. In his career, he has progressed from project engineer to project manager and lately senior project manager at several owner and contractor organizations, including the US contractor Jacobs Engineering and the Swiss pharmaceutical firm Novartis. He also previously worked as a consultant in capital project benchmarking. Lawrence is a chartered engineer in the UK, a registered professional engineer in the European Union, and a fellow of the UK Institution of Chemical Engineers. He is also a member of the American Institute of Chemical Engineers. He holds a bachelors in chemical engineering (1984) from Heriot-Watt University, Edinburgh, a masters (1985) in biochemical engineering from Birmingham University, England, and an MBA (1991) from Strathclyde University Business School in Glasgow.

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Navigating a Mine Field and Staying Safe — How Overlooking Instrumentation Could Cost You at Every Turn