

# PRACTICE EXAM 6: BOILER OPERATOR LICENSE SIMULATION

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## QUESTIONS 1–100

1. A boiler shows rising stack temperature over four weeks, increased fuel consumption per pound of steam, and reduced plant efficiency. Water chemistry and combustion tuning have not changed. The most probable root cause is:

- A. A sudden drop in ambient air temperature reaching the boiler
- B. Improved feedwater heating from deaerator performance
- C. Progressive scale accumulation on waterside tube surfaces
- D. Increased steam demand beyond the plant's rated capacity

2. An operator receives simultaneous alarms for low water, flame failure, and high stack temperature. The first-out annunciator shows "flame failure" as the initiating event. The most likely sequence of events is:

- A. Low water tripped first, then produced the other alarms in sequence
- B. Flame failure tripped first, then other alarms followed as conditions changed
- C. High stack temperature was the root cause of the cascade
- D. All three alarms tripped simultaneously from a common fault

3. A watertube boiler shows increased tube metal temperatures on one bank of riser tubes while water chemistry remains within specification. The most likely cause is:

- A. Excessive boiler water alkalinity requiring blowdown adjustment

- B. Incorrect chemical treatment program for the water supply
- C. Elevated stack temperature from normal firing conditions
- D. Reduced circulation through the affected tube bank

4. A boiler operator notices that the forced-draft fan motor current is 30 percent above its rated level during normal firing. The combustion air damper opens fully but the burner fires correctly. Investigation should focus on:

- A. Fouling of the fan impeller or inlet air screens
- B. Electrical supply voltage at the motor terminals
- C. Burner fuel pressure at the atomizer entrance
- D. Steam pressure controller tuning parameters

5. A deaerator is found venting heavily with a large steam plume while feedwater enters it at 180°F. Oxygen levels in feedwater downstream have also increased above specification. The most likely cause is:

- A. Excessive blowdown rate on the deaerator storage section
- B. High-pressure steam supply to the deaerator has increased
- C. Feedwater flow exceeding the deaerator's design capacity
- D. Chemical treatment delivering excess oxygen scavenger downstream

6. An operator finds that the pressure-reducing station downstream safety valve is lifting continuously while upstream pressure reads normal at 250 psig and downstream reads 90 psig (setpoint 100 psig). The most likely cause is:

- A. A failed-closed pressure-reducing valve blocking downstream flow
- B. A failed-open pressure-reducing valve causing downstream overpressure
- C. Calibration error on the downstream pressure gauge only

D. Normal operation because safety valves cycle during service

7. A feedwater pump delivers rated flow but the discharge pressure is 30 psi below the boiler operating pressure. Check valves are confirmed seated. The boiler water level is dropping during firing. The most likely issue is:

- A. Excessive suction head on the pump inlet line
- B. Blocked discharge piping between the pump and boiler
- C. Pump running at correct speed with no mechanical issue
- D. Impeller wear or fouling reducing pump's developed head

8. An operator observes that a boiler's total dissolved solids have climbed from 2,800 ppm to 3,900 ppm over two weeks with no change in blowdown rate. Makeup water quality has not changed. The most likely cause is:

- A. Reduced condensate return requiring increased makeup water
- B. Excessive chemical treatment overdosing the boiler water
- C. Failure of the surface blowdown control valve to open
- D. Improved deaerator performance reducing dissolved gases

9. A flame detector signal shows cycling on/off during burner operation. The burner continues to fire without shutdown. Most likely cause of this signal behavior is:

- A. A properly operating detector responding to normal flame flicker
- B. Failed BMS sequence logic during routine operation
- C. A deteriorating detector producing marginal signal strength
- D. Normal operation during extended modulating firing cycles

10. An operator finds water droplets on the gauge glass exterior but the glass itself reads a normal water level. The most likely explanation is:

- A. Internal gauge glass leak requiring immediate replacement
- B. Ambient condensation on a cold gauge surface in a humid environment
- C. Steam escape from the top gauge cock connection
- D. Water leak at the bottom gauge cock connection

11. A cast-iron heating boiler develops a crack in one section after 18 years of service. The plant operator wants to return the boiler to service quickly. The correct engineering approach is:

- A. Replace the cracked section with a matching new section
- B. Install a steel repair plate over the cracked area
- C. Weld the crack using standard carbon steel electrodes
- D. Apply epoxy sealant to stop the immediate leak

12. An operator notices that the condensate return temperature has fallen from 180°F to 140°F over a month. Steam consumption is unchanged. Trap survey shows no failures. The most likely cause is:

- A. Improved insulation on steam distribution piping
- B. Reduced firing rate producing cooler boiler water
- C. Lower ambient temperature in the mechanical room
- D. Longer condensate piping or damaged return-line insulation

13. A boiler's combustion analysis shows O<sub>2</sub> at 10 percent and CO at 400 ppm simultaneously. This unusual combination suggests:

- A. A properly tuned burner with optimal combustion conditions

- B. Poor mixing of fuel and air producing both conditions simultaneously
- C. A failed oxygen analyzer requiring calibration adjustment
- D. Normal cold-start conditions before full combustion

14. A boiler operating at 150 psig has an accumulation test result showing peak pressure of 164 psig. The lowest safety valve is set at 150 psig and the highest at 153 psig. Does this pass?

- A. No, 164 exceeds the 6 percent limit above highest setting
- B. Yes, 164 is below 6 percent above the lowest setting
- C. Yes, 164 is 7.2 percent above the highest setting but acceptable
- D. No, any pressure above 150 psig automatically fails the test

15. An operator observes that boiler water pH is 10.9, conductivity is 3,200  $\mu\text{S}/\text{cm}$ , and sulfite residual is 0 ppm. Dissolved oxygen upstream shows normal levels. The chemistry issue is:

- A. Oxygen scavenger feed has stopped while other treatment continues
- B. Excessive caustic soda has overdosed the treatment program
- C. Proper chemistry across all three measured parameters
- D. Water hardness breakthrough from softener regeneration failure

16. A boiler trips on low water fuel cutoff but the gauge glass shows normal water level. The LWCO has been recently tested. The most likely cause is:

- A. A failed LWCO requiring immediate replacement before restart
- B. Normal cycling of LWCO during routine operation
- C. Wrong setpoint programmed during the recent testing
- D. Sediment plugging in the LWCO float chamber creating false trip

17. An operator measuring flue gas finds CO<sub>2</sub> at 9 percent and CO at 150 ppm on a natural gas burner. The typical target for natural gas combustion efficiency suggests:

- A. Correct tuning at optimal combustion conditions
- B. Combustion is close to stoichiometric with some CO formation
- C. Combustion with excessive air cooling the flame
- D. Cold flame conditions preventing complete combustion

18. A boiler operator finds that ambient temperature in the boiler room has risen 20°F over two weeks while firing rate is unchanged. The most likely cause is:

- A. Improved insulation on boiler piping and equipment
- B. Reduced combustion air intake from restricted louvers
- C. Degraded insulation on steam and hot water piping systems
- D. Increased electrical load from additional plant equipment

19. A boiler's safety valve lifts at set pressure but reseats at a pressure 15 psi below the setting. The blowdown setting should be:

- A. Reduced to narrow the pressure differential before reseating
- B. Increased to widen the pressure differential before reseating
- C. Left alone because this represents normal operation
- D. Set to match the operating pressure setpoint exactly

20. An operator identifies that a feedwater pump suction pressure has dropped from 5 psig to -2 psig (vacuum). The most likely cause is:

- A. Excessive pump discharge pressure demand from the boiler

- B. Clogged suction strainer at the pump inlet
- C. Pump running above rated speed with controller error
- D. Low feedwater tank level producing reduced suction head

21. A boiler with a single-element feedwater regulator shows water level hunting continuously  $\pm 3$  inches from setpoint. Adjusting the regulator settings does not help. The fundamental problem is:

- A. The control scheme is inadequate for the load variability present
- B. The feedwater pump is oversized for the boiler's capacity
- C. The gauge glass is providing incorrect level signal information
- D. The boiler's water volume is too small for stable operation

22. An operator finds oil residue inside the boiler during internal inspection. The plant has no oil-fired equipment. The most likely source is:

- A. Lubrication oil from feedwater pump seals entering the boiler
- B. Fuel oil contamination through a failed heat exchanger tube
- C. Boiler water treatment chemicals producing oil-like deposits
- D. Condensate return contamination from process equipment

23. A watertube boiler's stack temperature drops suddenly by 50°F during firing. Steam pressure and firing rate are unchanged. The most likely cause is:

- A. Improved combustion tuning from automatic adjustment
- B. A tube rupture allowing water into the gas path
- C. Reduced feedwater temperature entering the boiler
- D. Normal variation from ambient temperature changes

24. An operator observes that the boiler's blowdown discharge appears black rather than the normal clear-to-cloudy white. The most likely cause is:

- A. Excessive alkalinity in the boiler water chemistry
- B. Oxygen scavenger concentration above specification
- C. Iron corrosion products accumulated in the boiler
- D. Normal color during certain chemical treatment cycles

25. A gauge glass shows water level rising steadily even when firing is at full rate and steam demand is high. The feedwater regulator is on automatic. Most likely cause:

- A. Failed feedwater regulator stuck in the fully open position
- B. Reduced boiler operating pressure from safety valve lift
- C. Excessive blowdown increasing apparent level
- D. Normal operation during transient load changes

26. An operator finds that boiler water dissolved oxygen is elevated despite proper deaerator operation. The feedwater chemistry treatment feeds sulfite continuously. Investigation should focus on:

- A. Excessive blowdown rate removing too much water
- B. Sulfite reaction rate at the current boiler temperature
- C. Incorrect alarm setting on the oxygen analyzer
- D. Feedwater piping leaks allowing air ingress downstream of deaerator

27. A burner produces a noisy "pulsing" combustion with audible resonance during firing. Flame appears unstable. The most likely root cause is:

- A. Correct air-fuel ratio producing normal combustion sounds

- B. Mismatched fuel and air supply creating combustion instability
- C. Normal burner operation during modulated firing rates
- D. Stack damper position limiting exhaust flow to atmosphere

28. An operator observes that the gauge glass water line is visibly turbulent with frothy white foam on top. This symptom is consistent with:

- A. Normal operation during steady-state load conditions
- B. Low-pressure boiler operating at reduced firing rate
- C. Foaming from chemistry contamination or high TDS
- D. Adequate feedwater treatment maintaining boiler health

29. A boiler's main steam stop valve is leaking past its seat during shutdown. This is evidenced by:

- A. Pressure in the boiler rising while offline from header pressure
- B. Reduced steam flow to downstream loads during operation
- C. Feedwater flow rate exceeding steam production temporarily
- D. Stack temperature rising without corresponding firing rate increase

30. An operator finds that water hammer occurs only when one specific branch line is opened from the header. The issue localizes to that branch. The most likely cause is:

- A. Boiler water chemistry affecting only that branch line
- B. Excessive steam pressure reaching that branch downstream
- C. Insufficient insulation on the branch piping to atmosphere
- D. Failed steam trap on that branch's drip leg arrangement

31. A feedwater pump operates normally during normal shifts but shuts down automatically during warm weather. The most likely cause relates to:

- A. Reduced feedwater chemistry requiring compensation
- B. Electrical supply voltage dropping in hot conditions
- C. Low NPSH from higher feedwater temperature in warm weather
- D. Motor winding insulation breaking down at high temperature

32. An operator measuring combustion efficiency finds stack temperature at 480°F, ambient at 70°F, and O<sub>2</sub> at 4 percent. On a natural gas burner, this represents efficiency of approximately:

- A. 65 percent efficiency at these conditions
- B. 80 percent efficiency at these conditions
- C. 90 percent efficiency at these conditions
- D. 95 percent efficiency at these conditions

33. A boiler's combustion air fan damper is fully open but firing rate is limited because combustion air proving is intermittent. The most likely cause is:

- A. Failed proving switch or restricted air inlet
- B. Correct operation during load transitions
- C. Excessive fuel supply pressure at the burner
- D. Boiler water chemistry affecting combustion stability

34. An operator observes that steam quality at the header has declined visibly with wet plumes visible at blowdown. Total dissolved solids are within specification at 2,500 ppm. The most likely cause is:

- A. Normal operation at reduced steam pressure

- B. Excessive firing rate beyond boiler capacity
- C. Improper blowdown affecting steam separators
- D. Operating water level too high causing priming

35. An operator finds that the bottom blowdown discharge has changed from clear to containing visible black flakes. The most likely cause is:

- A. Normal sediment removal during routine blowdown
- B. Iron scale detaching from waterside tube surfaces
- C. Burned fuel ash reaching the boiler through air intake
- D. Proper chemistry maintenance through regular blowdown

36. A pressure gauge has been calibrated, verified accurate, and installed on a boiler. Within a week, the gauge reads 15 psi higher than the calibrated pressure. The most likely cause is:

- A. Normal calibration drift requiring weekly recalibration
- B. Excessive vibration from nearby equipment affecting operation
- C. Heat damage from steam reaching the Bourdon tube mechanism
- D. Boiler water chemistry affecting gauge mechanism externally

37. A boiler's feedwater regulator is of two-element type. The operator observes that during load transients, water level experiences less overshoot but still some undershoot. The likely improvement:

- A. Upgrade to three-element control with feedwater flow input
- B. Reduce proportional gain on the existing controller
- C. Increase the feedwater pump capacity for faster response
- D. Change the steam flow sensor to a more accurate device

38. An operator notices that the boiler refractory in the burner throat shows white discoloration and slight pitting. The most likely cause is:

- A. Normal operation at sustained firing conditions
- B. Chemical attack from condensate reaching refractory
- C. Mechanical damage from flame impingement on refractory
- D. Thermal cycling and combustion gas attack on refractory

39. An operator measuring feedwater flow finds it is 20 percent higher than the steam flow produced. The difference is consistent over several hours. The most likely cause is:

- A. Normal variation between measurement instruments
- B. Significant blowdown rate above typical operation
- C. Measurement error in one of the two flow meters
- D. Steam leak in downstream distribution piping

40. A boiler's safety valve blowdown ring is adjusted from its factory setting. The valve now lifts correctly at the set pressure but reseats only 2 psi below. The change affects:

- A. The maximum allowable working pressure calculation
- B. The pre-purge requirement before burner ignition
- C. The blowdown differential between opening and closing
- D. The operating pressure control setting of the boiler

41. A boiler operator finds that the drum sight glass shows water level fluctuating rapidly ( $\pm 1$  inch in under 5 seconds). Firing rate is steady. The most likely cause is:

- A. Normal operation during modulated firing cycles

- B. Water surface disturbance from rapid steam evolution
- C. Feedwater pump cycling frequently during operation
- D. Steam pressure controller adjustment during load changes

42. A deaerator vent temperature drops from 240°F to 215°F over a shift. Feedwater output temperature also drops. Most likely cause:

- A. Increased steam supply to the deaerator overnight
- B. Reduced condensate return to the deaerator system
- C. Insufficient steam supply to the deaerator for heating
- D. Normal operation during low-load weekend conditions

43. An operator finds the condensate return pump running continuously at reduced flow rather than cycling on and off normally. The most likely cause is:

- A. Failed check valve on the pump discharge allowing recirculation
- B. Increased condensate return from the plant's heat loads
- C. Improved condensate return chemistry from treatment changes
- D. Normal operation during peak load conditions only

44. An operator observes that fuel gas pressure at the burner is fluctuating rapidly despite the gas train pressure regulator operating. The most likely cause is:

- A. Boiler water chemistry affecting combustion operations
- B. Steam pressure variations affecting fuel supply pressure
- C. Feedwater pump cycling creating fuel supply fluctuations
- D. Contaminated or failing gas pressure regulator diaphragm

45. A boiler operator identifies that the flame scanner signal drops below threshold only during low-fire operation. At higher firing rates, the signal is strong. The most likely cause is:

- A. Completely failed flame scanner requiring immediate replacement
- B. Scanner sensitivity or alignment issues at low firing conditions
- C. Normal operation where signals naturally vary with flame size
- D. BMS sequence logic error during modulated firing operation

46. An operator compares boiler efficiency testing results across seasons and finds efficiency is 3 percent lower in summer than winter. The most likely cause is:

- A. Better combustion tuning during winter operations only
- B. Reduced heating demand producing efficiency differences
- C. Higher ambient air temperature reducing combustion air density
- D. Water chemistry improvements during winter operations

47. A boiler's operating pressure control is set at 130 psig and the high-pressure limit is at 160 psig. Safety valves are set at 175 psig. The operator notices the operating control is cycling between 125 and 135 psig during normal operation. Most likely cause:

- A. High-pressure limit setpoint needs reduction to prevent nuisance
- B. Operating control differential is too narrow at the current setting
- C. Safety valve setpoint needs adjustment to match operating range
- D. Normal operation at rated firing across all pressure settings

48. An operator finds the boiler water sight glass has a layer of white precipitate on the bottom of the glass interior. The most likely cause is:

- A. Normal operating chemistry producing crystalline deposits

- B. Excessive alkalinity crystallizing from the water solution
- C. Silica carryover from high-pressure operation conditions
- D. Hardness breakthrough from the water softener system

49. A feedwater system operating a softener regenerating daily suddenly shows hardness in the softened water output. The cause most likely relates to:

- A. Normal operation during daily regeneration timing
- B. Salt depletion in the brine tank affecting regeneration
- C. Ambient temperature affecting softener resin performance
- D. Feedwater flow exceeding softener rated capacity

50. An operator on a steam heating system notices that radiators in distant zones are cold while nearby radiators are hot. Steam pressure at the boiler is normal. The most likely cause is:

- A. Failed trap or air vent on the distant zone piping
- B. Excessive steam pressure in the distant zone only
- C. Normal operation during warm outdoor conditions
- D. Insufficient insulation on the distant zone radiators

51. A boiler plant's gas consumption has increased 8 percent over a month with no change in steam output. Combustion testing shows 15 percent excess air, which is within normal range. The most likely cause is:

- A. Improved fuel quality reducing combustion energy output
- B. Better combustion tuning from recent maintenance activities
- C. Reduced boiler efficiency from accumulated minor issues
- D. Scale or soot accumulation reducing heat transfer efficiency

52. An operator identifies that the boiler's steam header pressure has become progressively unstable with larger swings than normal. Steam flow to loads is unchanged. The most likely cause is:

- A. Normal variation during modulated firing operations
- B. Successful load balancing across multiple boilers
- C. Pressure-reducing valve chattering in the distribution piping
- D. Feedwater chemistry improvements affecting steam quality

53. An operator notices that automatic chemical treatment pump is running but no chemical is being delivered to the boiler water. The chemical reservoir level is not dropping. The most likely cause is:

- A. Normal operation during low chemistry demand periods
- B. Blocked discharge line or failed chemical feed pump diaphragm
- C. Excessive chemical treatment from the previous shift operation
- D. Water chemistry already within specification requiring no feed

54. A boiler with multiple safety valves shows one valve lifting before the others at lower pressure. The most likely cause is:

- A. Setting drift of that specific valve below the others
- B. Difference in valve size requiring correction
- C. Normal operation with valves lifting at different times
- D. Fault in the control system affecting only that valve

55. A firetube boiler shows soot buildup more severely on the lower tubes than upper tubes of the same bank. The most likely cause is:

- A. Normal combustion gas flow patterns producing soot differences

- B. Improved combustion tuning in upper sections of boiler
- C. Water treatment chemistry affecting tube cleanliness differently
- D. Cooler lower tubes producing more combustion gas condensation

56. An operator finds that the boiler's feedwater pump starts, runs briefly, and stops repeatedly in short cycles without delivering adequate flow. The most likely cause is:

- A. Normal operation during periods of low feedwater demand
- B. Excessive discharge pressure exceeding the pump's rated capacity
- C. Air binding in the pump suction line preventing continuous operation
- D. Motor electrical issues affecting the pump operation cycles

57. An operator observes that the steam trap on a heat exchanger has become noticeably cooler than the steam line feeding it. The trap was working normally yesterday. The most likely cause is:

- A. Normal operation during reduced process heat demand
- B. Failed trap stuck shut, blocking condensate flow
- C. Excessive steam pressure reaching the heat exchanger
- D. Improved heat exchanger efficiency recently achieved

58. A boiler's feedwater system uses a three-element controller. During a sudden 40 percent steam demand increase, water level drops 2 inches before recovering. The response suggests:

- A. Normal operation with expected transient level excursion
- B. Controller proportional gain needs significant reduction
- C. Feedwater pump is undersized for the load transient
- D. Three-element control is inadequate for this application

59. An operator notices that the boiler's stack damper position is closed further than during normal operation even though firing rate is unchanged. The most likely cause is:

- A. Normal operation during stable firing conditions
- B. Reduced combustion air requirements from tuning
- C. Excessive draft causing damper modulation toward closure
- D. Progressive tube fouling increasing resistance and reducing flow

60. A boiler water chemistry test shows pH at 10.9, conductivity at 5,200  $\mu\text{S}/\text{cm}$  (above 4,000  $\mu\text{S}/\text{cm}$  specification), and sulfite residual at 45 ppm (above 30 ppm target). The correct operator response is:

- A. Increase all chemical feed rates to restore chemistry
- B. Reduce feedwater flow to slow chemistry accumulation
- C. Increase surface blowdown to reduce conductivity only
- D. Stop all chemical feed to allow chemistry to normalize naturally

61. An operator observes that the condensate return tank has accumulated standing water on the floor around it, visible through a small leak at the tank's bottom seam. The most likely cause is:

- A. Normal condensation on the tank exterior surfaces only
- B. Overfilled tank causing overflow through vent piping
- C. Internal cleaning chemicals leaking from the storage tank
- D. Tank corrosion producing a pinhole leak in the bottom

62. A boiler's steam flow metering shows flow that is 15 percent higher than makeup + condensate return combined. The chemistry water balance calculation is off by this same percentage. The most likely cause is:

- A. Normal variation between different measurement systems

- B. Significant steam leak somewhere in the distribution system
- C. Steam flow meter incorrectly calibrated from factory settings
- D. Measurement methodology differences producing the apparent discrepancy

63. An operator finds the feedwater pump has developed a noisy bearing sound. The pump continues to operate normally but the sound is concerning. The best next action is:

- A. Schedule bearing replacement at the next planned maintenance outage
- B. Continue operation indefinitely since the pump is working
- C. Change the pump lubricant immediately without inspection
- D. Increase pump speed to mask the bearing noise temporarily

64. A boiler's main combustion air fan trips on motor overload during startup. Investigation finds the fan is operating normally once restarted. The most likely cause is:

- A. Motor electrical supply insufficient for starting torque
- B. Bearing failure on the fan shaft requiring replacement
- C. Damper restricting airflow at startup from frozen position
- D. Motor winding issue developing over operating hours

65. An operator identifies that combustion air oxygen levels (measured upstream of burner) are elevated above atmospheric concentrations. This unusual finding suggests:

- A. Normal operation during intake air sampling tests
- B. Oxygen enrichment in the combustion air supply
- C. Measurement error from defective sensor calibration
- D. Leakage of oxygen-rich gas into the combustion air path

66. A boiler's feedwater temperature has dropped from 220°F to 180°F over a week. Investigation shows normal deaerator operation and condensate return rates. The most likely cause is:

- A. Reduced heat transfer in the feedwater preheater or economizer
- B. Lower ambient temperature affecting deaerator performance
- C. Chemistry contamination affecting heat transfer internally
- D. Higher-than-rated feedwater flow reducing temperature rise

67. An operator observes an increased frequency of safety valve lifting during normal operation. The safety valve setpoint has not changed. The most likely cause is:

- A. Operating control setpoint drifting upward closer to safety valve setting
- B. Normal variation in safety valve performance over time
- C. Improved boiler performance producing more steam consistently
- D. Chemistry changes affecting boiler water characteristics

68. A boiler's combustion system shows CO in flue gas at 50 ppm, O<sub>2</sub> at 2 percent, and combustion efficiency at 82 percent. The typical target for natural gas combustion:

- A. Too much excess air for optimal efficiency
- B. Too little excess air producing CO emissions
- C. Insufficient oxygen for complete combustion cycle
- D. Operating within typical efficiency targets for good tuning

69. An operator on a watertube boiler finds that the saturation temperature displayed on the drum pressure gauge-temperature combination does not match the actual measured temperature by 30°F. The gauge side matches the pressure correctly. The most likely cause is:

- A. Normal operation during modulated firing conditions

- B. Improved deaerator performance affecting feedwater chemistry
- C. Thermometer fouled or failing, providing incorrect temperature
- D. Normal variation between pressure-derived and measured values

70. A boiler's steam trap survey identifies 18 failed-open traps in a plant of 95 traps. The survey is scheduled annually. The most appropriate response is:

- A. Continue annual surveys because the failure rate is acceptable
- B. Replace failed traps and consider more frequent survey intervals
- C. Reduce survey intervals since most traps are functioning
- D. Investigate each trap individually without repairing the failures

71. An operator compares current internal boiler inspection findings to last year's report. The current year shows new corrosion spots not present before. The most probable cause relates to:

- A. Changed feedwater chemistry or equipment fault affecting corrosion
- B. Normal aging of the boiler affecting corrosion rates
- C. Improved inspection techniques revealing previous corrosion
- D. Inspector variation in recording corrosion observations

72. A boiler operator identifies that fuel oil atomization appears coarse, producing visible soot despite correct oil temperature. The preheater is operating normally. The most likely cause is:

- A. Correct atomization producing normal flame characteristics
- B. Boiler water chemistry affecting combustion externally
- C. Normal variation during modulated firing operations
- D. Atomizing medium pressure (steam or air) below specification

73. An operator finds that cooling tower blowdown water (from the separate HVAC plant) is being mistakenly used as boiler makeup water occasionally. The correction involves:

- A. Mixing the cooling tower water with softened water to reduce TDS
- B. Accepting the water as emergency makeup during critical times
- C. Isolating the systems and establishing proper makeup water only
- D. Chemical treatment to compensate for the improper water source

74. A boiler's total fuel consumption has dropped 5 percent over a month but steam production is unchanged. The plant manager attributes this to "efficiency improvements." The operator's assessment:

- A. Celebrate the improvement without further investigation into sources
- B. Investigate the cause to verify the improvement is genuine
- C. Increase firing rate to match historical fuel consumption patterns
- D. Adjust chemistry to match the apparent efficiency improvement

75. An operator observes that combustion air damper actuator is operating audibly with hissing sound during modulation. The damper position appears correct. The most likely cause is:

- A. Air leak in the pneumatic actuator diaphragm or fittings
- B. Normal operation during damper positioning cycles only
- C. Electrical actuator operating at correct position signals
- D. Boiler water chemistry affecting the actuator operation

76. A boiler plant has both a primary and secondary feedwater pump for redundancy. The primary has been running continuously for 6 months. The operator should:

- A. Continue primary operation until the next scheduled maintenance

- B. Allow the primary to run until failure occurs then switch pumps
- C. Start the secondary to verify functionality once per shift
- D. Rotate pumps periodically to maintain both in serviceable condition

77. An operator notices that an inverted bucket steam trap appears stuck fully submerged in condensate without cycling. The most likely cause is:

- A. Trap operating correctly under very high condensate flow
- B. Excessive steam pressure preventing normal bucket operation
- C. Clogged vent hole in the top of the inverted bucket
- D. Normal operation during low-load boiler conditions only

78. A boiler's condensate return water shows visible yellow discoloration in a previously clear system. Testing reveals elevated iron content. The most likely cause is:

- A. Normal condensate aging producing color changes over time
- B. Corrosion in condensate return piping due to acidic conditions
- C. Chemical treatment carrying iron into the condensate system
- D. Feedwater chemistry contamination affecting condensate appearance

79. An operator finds the boiler's feedwater line check valve is not seating properly (evidenced by reverse flow when pump stops). The most likely consequence is:

- A. Hot boiler water flowing back through the feedwater system
- B. Excessive pump cycling from backflow protection measures
- C. Steam escaping through the feedwater piping network
- D. Chemistry imbalance from feedwater flow interruptions

80. A boiler's flame scanner shows a clear flame signal, but the BMS will not permit ignition on a cold-start attempt. The combustion air fan is running. The most likely cause is:

- A. Insufficient steam pressure for the ignition attempt
- B. Flame scanner malfunction requiring replacement verification
- C. Pre-purge cycle not yet completed to minimum air changes
- D. Proof-of-closure switch on a fuel valve showing open condition

81. An operator compares fuel consumption data between two identical boilers operating at the same load. One boiler uses 12 percent more fuel. Investigation should focus on:

- A. Steam header pressure affecting boiler performance differently
- B. Feedwater chemistry differences between the two boilers
- C. Heat transfer differences (fouling, scale, soot) between units
- D. Combustion tuning differences affecting operation only

82. A pressure gauge on a boiler reads 145 psig while the boiler's operating pressure control is set to cut out at 150 psig. The gauge was recently calibrated. The boiler is not cycling. The most likely cause is:

- A. Operating control setpoint has drifted below the cut-out value
- B. Pressure gauge has drifted and needs recalibration again
- C. Normal operation with pressure varying during firing cycles
- D. Safety valve has lifted and is still passing steam externally

83. A boiler operator identifies that blow-down conductivity is consistently  $3\times$  the feedwater conductivity, but was historically  $5\times$  the feedwater conductivity. The most likely cause is:

- A. Reduced makeup water hardness from improved treatment

- B. Increased blowdown rate reducing the concentration ratio
- C. Normal variation in the treatment cycle timing
- D. Improved condensate return reducing feedwater conductivity

84. An operator finds that the deaerator storage level is dropping despite normal makeup water supply. Chemical feed rates are normal. The most likely cause is:

- A. Normal operation during low-load weekend conditions
- B. Reduced feedwater demand from the boiler system
- C. Improved condensate return to the deaerator system
- D. Excessive feedwater demand or water loss somewhere downstream

85. A boiler's combustion efficiency drops from 83 percent to 78 percent over three months. O<sub>2</sub> levels have risen from 3 percent to 6 percent at full fire. The most likely cause is:

- A. Drift in combustion control causing excess air increase
- B. Improved feedwater treatment affecting combustion tuning
- C. Normal seasonal variation in combustion efficiency
- D. Reduced ambient temperature affecting combustion air density

86. An operator on a plant with three boilers observes that the three-boiler common header pressure swings when any single boiler's firing rate changes. The root cause likely relates to:

- A. Normal operation across multiple boilers on a common header
- B. Feedwater chemistry imbalance between the three boilers
- C. Master pressure controller or load-sharing configuration error
- D. Safety valve settings differing between the three boilers

87. A boiler's gauge glass shows a rapid drop in water level of 4 inches over 2 minutes. Steam demand has not changed. The first-out annunciator shows nothing. The most likely cause is:

- A. Normal operation during reduced firing rate periods only
- B. Feedwater supply interruption or pump failure event
- C. Water chemistry change affecting apparent level indication
- D. Improved steam separation producing lower visible water

88. An operator observes that combustion air entering the boiler room produces noticeable cold drafts at the intake louvers. The louver is fully open. The combustion air fan operation appears normal. The most likely concern is:

- A. Reduced boiler efficiency from cold air inlet temperature
- B. Normal operation during cold outdoor conditions unchanged
- C. Excessive combustion air reducing flame temperature
- D. Winter weather affecting boiler operation without consequences

89. A boiler's steam flow has declined 10 percent over 2 weeks while firing rate is unchanged. The operator is receiving load complaints from the plant. The most likely cause is:

- A. Boiler efficiency decline from fouled tubes or other reasons
- B. Improved insulation reducing apparent steam flow measurements
- C. Normal seasonal variation in steam demand affecting flow
- D. Feedwater temperature increase producing less apparent flow

90. An operator identifies that saturated steam leaving the boiler has slightly higher moisture content than normal. Boiler water level is correct. The most likely cause is:

- A. Improved feedwater treatment reducing steam quality apparently

- B. Normal operation at reduced firing rates producing variation
- C. Failing steam separator internals in the steam drum
- D. Reduced ambient temperature affecting steam measurement

91. A boiler's low water fuel cutoff is being tested by slow drain. The water level reaches the cutoff point but the burner shuts off approximately 10 seconds later. The assessment is:

- A. The cutoff is functioning correctly within typical delay tolerance
- B. The cutoff is operating slower than specified and should be adjusted
- C. Normal variation in cutoff response times across units
- D. The test results do not meet minimum safety requirements

92. An operator on a plant observes that the boiler room temperature is steadily rising while outdoor temperature is constant. The cause is most likely:

- A. Excessive combustion air drawing heated air into the boiler
- B. Normal operation during cold seasons requiring extra heating
- C. Boiler operation at reduced firing rate producing more heat
- D. Heat loss from equipment, piping, or boiler into the room

93. A boiler operator finds that the fuel oil temperature gauge on a No. 6 oil system reads only 100°F, below the 185°F operating specification. Firing has not yet begun. The most likely cause is:

- A. Oil preheater has not reached operating temperature yet
- B. Normal operation during low-load conditions for this oil grade
- C. Fuel oil has been changed to a lower-grade oil
- D. Preheater is damaged and requires immediate replacement

94. An operator identifies that the combustion air fan runs at full speed even at low fire. The firing rate is 40 percent of rated. The most likely cause is:

- A. Normal operation with air damper modulating while fan runs constantly
- B. Improved boiler efficiency requiring less air modulation
- C. Air-fuel ratio control setting requiring verification or adjustment
- D. Excessive air damper position exceeding the firing requirement

95. A boiler's annual inspection reveals uniform tube wall thinning in the economizer tubes. The most likely cause is:

- A. Normal tube wear from long-term operation
- B. Dew-point corrosion from stack gas condensation in the economizer
- C. Oxygen pitting corrosion from dissolved oxygen attack
- D. Chemistry contamination affecting tube surfaces uniformly

96. An operator observes that the boiler's feedwater regulator valve is not responding to control signal. The valve is held fully open. Water level is climbing above normal. The most likely cause is:

- A. Failed valve actuator stuck in the fully open position
- B. Normal operation during startup sequence requirements
- C. Valve repositioning during modulated firing operations
- D. Increased steam demand requiring higher feedwater flow

97. A boiler room has experienced three near-miss incidents involving steam releases in the past year. The events have not caused injury but reflect recurring issues. The most appropriate organizational response is:

- A. Investigate each event as isolated incidents without pattern analysis

- B. Accept near-misses as inevitable given boiler operation complexity
- C. Wait for a serious incident before changing any plant procedures
- D. Conduct a systematic root-cause analysis across all three events

98. An operator finds the combustion analysis equipment (oxygen and CO analyzers) has not been calibrated in 8 months. The equipment is used for daily combustion testing. The correct action is:

- A. Continue using the equipment until readings appear obviously wrong
- B. Reduce the frequency of testing to minimize equipment wear
- C. Arrange immediate calibration before further use in testing
- D. Purchase new equipment instead of calibrating older equipment

99. A boiler's pressure-reducing valve on a steam line to a low-pressure process has failed closed. Downstream equipment has shut down. The operator's correct action is:

- A. Force the valve open by adjustment to restore flow quickly
- B. Switch to bypass piping while arranging PRV repair
- C. Accept the shutdown and wait for normal operations to resume
- D. Increase upstream pressure to compensate for the valve failure

100. An operator identifies that a fuel gas leak has been detected by the plant's gas detection system. The detector is showing an active warning condition. The first action is:

- A. Evacuate the affected area and isolate fuel supply at the source
- B. Investigate the source of the leak while maintaining boiler operation
- C. Increase ventilation to disperse the gas before taking other action
- D. Continue operation while the leak is being located for repair

# PRACTICE EXAM 6: ANSWER KEY

## AND FULL EXPLANATIONS

### (QUESTIONS 1–100)

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1. C — Progressive scale accumulation on waterside tube surfaces insulates the tubes and reduces heat transfer, causing heat to leave through the stack at higher temperature while more fuel is required to produce the same steam. The three symptoms — rising stack temperature, higher fuel consumption, and falling efficiency — together form the classic fouling signature. Tube cleaning restores efficiency.
2. B — Flame failure as the first-out alarm is the initiating event; low water followed as firing stopped and steam demand continued without makeup compensation adjustment. High stack temperature resulted from whatever combustion disturbance caused the flame failure. First-out annunciation is the definitive tool for identifying the root cause of cascaded alarms.
3. D — Reduced circulation through a tube bank allows tube metal to overheat because the water normally cooling the tubes is no longer flowing. Scale, plugging, or collapsed internals typically cause localized circulation loss. Chemistry within specification rules out system-wide water treatment issues.
4. A — Fan motor current 30 percent above rated is classic fan overload, typically caused by fouled impeller or restricted air intake screens that increase aerodynamic load. Electrical supply issues would typically cause low rather than high current. The burner firing correctly rules out fuel or pressure control as causes.
5. C — Feedwater flow exceeding deaerator design capacity produces heavy venting because the unit cannot heat the incoming water to saturation for proper gas removal. Excess unheated water then carries dissolved oxygen through to the feedwater system. Capacity mismatch between deaerator and feedwater demand is a common diagnostic finding.
6. B — A failed-open PRV allows upstream pressure (250 psig) to reach downstream equipment, causing pressure to rise above the downstream safety valve setpoint (100 psig). The safety valve then lifts continuously to protect downstream piping. This is exactly why downstream safety valves are mandatory on pressure-reducing stations.
7. D — Impeller wear or fouling reduces pump's developed head, so discharge pressure falls below what is needed to overcome boiler pressure plus piping losses. Water flow drops and boiler water

level begins to fall. Check valve seating rules out backflow; suction head issues would typically cause cavitation rather than just low head.

8. A — Reduced condensate return requires increased fresh makeup water, which carries dissolved solids into the feedwater system. Over time, TDS in the boiler water climbs because more TDS is entering per pound of steam produced. Addressing the condensate return reduction is the root cause correction.
9. C — A deteriorating flame detector produces marginal signal strength that cycles above and below the BMS threshold. The burner continues to fire because the signal periodically rises above threshold, but the cycling pattern is a red flag for upcoming complete failure. Detector replacement should be scheduled promptly.
10. B — Water droplets on the gauge glass exterior with normal water level inside is classic ambient condensation in a humid boiler room. The cool glass surface condenses moisture from the surrounding air. Actual leaks would show water draining from a specific connection, not uniform condensation on the glass.
11. A — Cast-iron sectional boilers are designed with replaceable sections specifically for this scenario. Replacing the cracked section with a matching new section is the proper repair method. Welding cast iron with steel electrodes is not appropriate; steel plates and epoxy do not meet code for pressure-boundary repair.
12. D — Longer condensate piping or damaged return-line insulation allows more heat loss as condensate travels back to the boiler plant, reducing temperature by time of arrival. Trap surveys ruled out trap failures; firing rate and steam consumption unchanged rule out load-related causes. Insulation condition is a recurring maintenance concern.
13. B — Poor mixing of fuel and air can simultaneously produce high O<sub>2</sub> (air bypassing combustion) and high CO (fuel finding no oxygen locally) — an unusual but diagnostic pattern. Normal well-tuned combustion shows low O<sub>2</sub> with low CO. Failed analyzer is possible but should be ruled out by cross-checking rather than assumed.
14. A — 164 psig is 7.2 percent above the highest valve setting of 153 psig, exceeding the 6 percent code limit. The test fails and additional safety valve capacity is required. Calculation:  $(164 - 153) / 153 \times 100 = 7.2\%$ . Any reading above the 6% limit requires corrective action.
15. A — Normal pH and conductivity with zero sulfite residual indicates the oxygen scavenger feed has stopped while pH and dispersant treatments continue. Sulfite is consumed by dissolved oxygen, so zero residual means either no feed or massive oxygen ingress. The dissolved oxygen check rules out ingress; the feed system needs attention.
16. D — Sediment in the float chamber traps the float at apparent normal position, but when water drops rapidly, sediment can release the float — causing an unexpected trip. Daily blowdown

prevents this scenario, which is why it's a life-safety procedure. Recent testing does not protect against sediment that has since accumulated.

17. B — Combustion near stoichiometric with 9 percent CO<sub>2</sub> (typical of near-stoichiometric operation) and 150 ppm CO indicates combustion with some incomplete burning at the margin. Well-tuned natural gas combustion typically achieves 9–11 percent CO<sub>2</sub> with CO below 100 ppm. Slight tuning adjustment would improve this result.
18. C — Degraded insulation on steam and hot water piping raises ambient temperature in the boiler room because more heat escapes into the space rather than being delivered to loads. Firing rate unchanged eliminates increased heat production as the cause. Insulation maintenance is a common contributor to gradually rising ambient conditions.
19. A — A reseal pressure 15 psi below the set point represents excessive blowdown (the pressure differential between opening and reseating). Reducing the blowdown setting by adjusting the blowdown ring narrows this differential to the typical 2–4 percent of set pressure. A 15 psi differential on a typical 100-150 psig setpoint exceeds normal tolerance.
20. D — Low feedwater tank level reduces suction head at the pump inlet, causing suction pressure to drop and potentially reach vacuum conditions. A clogged suction strainer would cause similar symptoms but is secondary to the more common cause of simply low tank level. Verifying tank level is typically the first troubleshooting step.
21. A — Single-element feedwater control uses only water level as the control signal, making it reactive rather than anticipatory. On variable loads, this produces continuous hunting as the controller chases level changes. Upgrading to two- or three-element control with steam flow input eliminates this hunting behavior.
22. A — Lubrication oil leaking from feedwater pump seals is the most common source of oil contamination in a boiler with no fuel oil system. Seal wear allows oil to enter the feedwater stream. Fuel oil contamination through failed heat exchanger is impossible without an oil-fired unit; chemistry and condensate sources typically don't produce visible oil.
23. B — A sudden 50°F stack temperature drop while firing rate is unchanged is classic evidence of a tube rupture — water injected into the gas path cools combustion gases dramatically. This is a serious failure requiring immediate shutdown and investigation. Gradual changes would indicate other causes; the suddenness is the diagnostic clue.
24. C — Blackish blowdown water indicates iron corrosion products accumulated in the boiler — typically from oxygen pitting, acidic conditions, or chemistry drift. Clear or cloudy-white blowdown is normal. Iron in blowdown is a warning of active corrosion that must be investigated through chemistry testing.
25. A — A failed feedwater regulator stuck in the fully open position allows continuous feedwater flow regardless of actual need, causing water level to rise despite high steam demand. This is a

potentially dangerous condition that can lead to carryover. Automatic mode failure doesn't stop the mechanical fault in the valve itself.

26. D — Feedwater piping leaks downstream of the deaerator allow atmospheric oxygen to enter the treated water, re-contaminating it despite proper deaerator operation. Sulfite feed cannot keep up with continuous oxygen ingress. Checking piping integrity between deaerator and boiler inlet is the diagnostic next step.
27. B — Combustion instability from mismatched fuel and air supply produces the pulsing and resonance described — a pressure oscillation phenomenon sometimes called "rumble." It damages equipment and indicates control system issues. Proper combustion should be smooth and stable, not pulsing.
28. C — Frothy foam on the water surface indicates foaming from chemistry contamination or high TDS — surface tension changes cause the water surface to froth. This is a precursor to carryover and can damage downstream equipment. Chemistry investigation and blowdown are the typical corrective actions.
29. A — A leaking main steam stop valve allows pressure to rise while the boiler is offline from the header pressure. This is diagnostic of internal seat damage. Normal operation would maintain the pressure differential, not equalize it. Repair or replacement is typically required for the leaking valve.
30. D — Water hammer localized to a specific branch line points to a failed steam trap on that branch's drip leg. The trap cannot discharge accumulated condensate, which then produces the characteristic hammering. The problem correlates with branch-specific equipment, not system-wide factors.
31. C — Higher feedwater temperature in warm weather reduces NPSH at the pump inlet. Hot water near saturation flashes to steam at the impeller inlet when NPSH is inadequate, causing the pump to lose prime and trip. This seasonal pattern is diagnostic.
32. B — 80 percent is typical efficiency for natural gas combustion at these conditions. Excess air at 4 percent O<sub>2</sub> (approximately 20% excess air) with 480°F stack temperature corresponds to approximately 80% combustion efficiency using standard fuel-to-steam calculations. Well-tuned modern boilers typically achieve 78–85%.
33. A — Failed proving switch or restricted air inlet are the most common causes of intermittent combustion air proving. Normal operation should provide consistent proving signal. Switch troubleshooting and inlet inspection are the standard diagnostic steps.
34. D — High water level causes priming and carryover, producing visible wet steam in the header despite normal TDS. The water level issue must be corrected directly — lowering level below the turbulent zone. Chemistry within specification rules out carryover from chemistry contamination.

35. B — Iron scale detaching from waterside surfaces appears as black flakes in bottom blowdown, indicating that previously-deposited scale is releasing — typically after chemistry changes that reduce the scale-forming tendency. This is actually a sign that chemistry improvements are working, but the released scale must be removed through continued blowdown.
36. C — Heat damage from steam reaching the Bourdon tube is the classic cause of gauge calibration drift after installation. The gauge siphon must be primed to protect the mechanism from direct steam exposure. This is why siphons are required on all steam pressure gauges.
37. A — Two-element control's reduced overshoot but remaining undershoot is typical, and three-element control with feedwater flow verification would eliminate this. The upgrade addresses the remaining closed-loop gap where actual feedwater flow isn't confirmed against demand.
38. D — Thermal cycling and combustion gas attack produce the discoloration and pitting described — normal wear patterns on refractory in the burner throat area. Routine refractory inspection and planned maintenance are standard practice. Complete failure would show more dramatic deterioration.
39. B — Significant blowdown rate above typical operation can produce 20% difference between feedwater flow and steam production. The difference is explained by water leaving the boiler as hot blowdown rather than as steam. This is normal when blowdown is excessive; verifying blowdown rate is the troubleshooting step.
40. C — Blowdown ring adjustment on a safety valve affects the blowdown differential — the pressure drop between opening and reseating. It does not affect MAWP, pre-purge, or operating control settings. Understanding what this adjustment changes matters for proper valve setup.
41. B — Rapid level fluctuation ( $\pm 1$  inch in under 5 seconds) with steady firing is typical turbulence at the steam-water interface from rapid steam evolution. This is normal operation for a boiler producing steam actively. Other level instruments should read steadier; the gauge glass sees surface conditions.
42. C — Insufficient steam supply to the deaerator causes lower operating temperature — the deaerator cannot heat feedwater fully to saturation for gas removal. This is the diagnostic pattern: both vent temperature and feedwater output drop together. Steam supply must be restored for proper deaerator function.
43. A — A failed check valve on the pump discharge allows water to recirculate through the stopped pump, so the running pump draws water that immediately returns — appearing as continuous operation with reduced apparent flow. Normal load variations produce different patterns.
44. D — Contaminated or failing gas pressure regulator is the typical cause of rapid fuel gas pressure fluctuations at the burner despite regulator presence. Regulator diaphragm deterioration produces erratic regulation. Internal contamination or mechanical wear are common causes requiring regulator service.

45. B — Scanner sensitivity or alignment issues at low firing conditions produce signal drop because low fire has smaller, dimmer flame. The scanner may require repositioning or replacement. High firing signals being strong rules out complete scanner failure.
46. C — Higher ambient air temperature in summer reduces combustion air density — more volume but less mass of oxygen per unit volume. This shifts combustion conditions slightly and can reduce efficiency. Seasonal variation in combustion efficiency is a known phenomenon worth understanding.
47. B — Operating control differential 5 psig cycle (125–130–135) is too narrow for stable operation, causing frequent cycling between firing and standby. Widening the differential (e.g., 125–135 or 120–140) reduces cycling frequency. This is a tuning issue, not a problem with limit or safety valve settings.
48. D — Hardness breakthrough from the softener system produces white crystalline precipitate — calcium carbonate or magnesium hydroxide deposits — on the gauge glass. Softener failure is a common cause. Investigation of softener regeneration and performance is the typical troubleshooting path.
49. B — Salt depletion in the brine tank is the most common cause of hardness breakthrough — without salt, regeneration cannot restore the ion-exchange capacity of the resin. Checking and replenishing salt is a basic maintenance item. Regeneration schedule alone doesn't address depleted salt.
50. A — Failed trap or air vent on distant zone piping prevents steam from reaching the remote radiators. Air accumulation blocks steam flow, and failed traps lock condensate in place. This is a typical heating system diagnostic scenario. Radiator-level issues typically localize to specific zones.
51. D — Scale or soot accumulation reducing heat transfer efficiency is the most likely cause of gradual fuel consumption increase without combustion changes. The heat transfer degradation requires more fuel to produce the same steam. Tube cleaning restores efficiency.
52. C — PRV chattering in distribution piping produces the progressive pressure instability described. The PRV may have developed seat damage or be operating near its stability limit. Repair or replacement of the PRV typically stabilizes the system. Chattering is often audible as well as creating pressure disturbance.
53. B — Blocked discharge line or failed chemical feed pump diaphragm produces the described symptom — pump running but no chemical delivered. The chemical reservoir level not dropping confirms no flow. Checking the discharge path and inspecting the pump head typically finds the failure point.
54. A — Setting drift of one valve below the others causes that valve to lift at lower pressure than the others. Proper adjustment or replacement of the drifted valve restores correct staged operation.

Size differences would be unusual on a multi-valve installation, and proper operation should lift valves at close-to-set pressures.

55. D — Cooler lower tubes produce more combustion gas condensation (dew-point crossing), which deposits more soot in the wet gas stream. The condensation mechanism is well documented in boiler operation — temperature patterns determine where soot deposits. Combustion tuning and gas flow patterns don't explain tube-specific differences.
56. C — Air binding in the pump suction line prevents continuous operation because the air interrupts water flow. The pump starts, briefly draws water, then pulls air and loses prime. Venting air from the suction line restores normal operation. Check valve issues or other causes would produce different patterns.
57. B — A steam trap stuck shut blocks condensate flow, so the trap temperature drops as condensate accumulates cold instead of at saturation temperature. A working trap with steam on the upstream side is hot; a blocked trap cools as condensate accumulates. This is a diagnostic temperature signature.
58. A — Normal operation with expected transient level excursion is the correct assessment — 2 inches of level drop during a 40% sudden demand increase is well within normal range for three-element control. Tuning adjustments or equipment changes are not indicated for normal transient response.
59. D — Progressive tube fouling increases resistance to gas flow, and the stack damper closes to compensate — the automatic draft control reduces damper opening to maintain draft pressure. This is a diagnostic sign of fouling developing gradually. Confirmation comes from checking tube condition.
60. C — Increasing surface blowdown reduces conductivity (TDS) without affecting pH and sulfite levels. All three parameters need individual attention; conductivity is above specification and requires blowdown while other parameters are within specification. Chemical feed adjustments would affect multiple parameters simultaneously.
61. D — Tank corrosion producing a pinhole leak is the typical cause of standing water around a condensate tank with a visible bottom-seam leak. Condensation outside the tank would not produce a localized leak point; overfilling would show different symptoms.
62. B — A 15 percent discrepancy between steam flow and water balance indicates a significant steam leak in the distribution system. The magnitude is too large for measurement variation alone. Finding and repairing the leak restores the water balance and reduces fuel consumption.
63. A — Scheduling bearing replacement at the next planned maintenance outage balances safety with operational continuity. The pump is working but showing developing failure; immediate replacement might not be feasible but continued operation indefinitely risks sudden failure. Planned maintenance is the appropriate response.

64. C — Damper restricting airflow at startup from a frozen position causes motor overload during the initial draw. Once the damper breaks free, the motor operates normally. This is a diagnostic pattern — problem only at startup suggests mechanical binding.
65. D — Leakage of oxygen-rich gas into combustion air is the most likely explanation for elevated oxygen in combustion air. Oxygen enrichment equipment is rare on boilers; intake contamination from oxygen plants or other gas sources nearby could cause this reading. Investigation is required.
66. A — Reduced heat transfer in the feedwater preheater or economizer directly reduces feedwater temperature at the boiler inlet. Scale or fouling on these heat exchangers reduces their effectiveness. Investigation of the feedwater heating equipment identifies the root cause.
67. A — Operating control setpoint drift upward toward the safety valve setpoint causes more frequent lifting as the operating pressure approaches the safety valve setting. This is a common operator finding requiring controller recalibration. Small setpoint drift has large effects on cycling frequency.
68. D — 82 percent efficiency with 2% O<sub>2</sub> and 50 ppm CO represents well-tuned natural gas combustion. The excess air is at the lower end of the typical 5–15% range, producing low CO and reasonable efficiency. This is a target-quality operating condition.
69. C — A fouled or failing thermometer provides incorrect temperature reading while pressure-derived temperature remains correct. Since pressure matches the actual saturation relationship, the thermometer is the suspect component. Cleaning or replacing the thermometer resolves the issue.
70. B — 18 failed-open traps in 95 traps (19% failure rate) is higher than typical and warrants both immediate repair and more frequent survey intervals. Industry norms suggest 10-15% failures in well-maintained plants; higher rates indicate systemic issues requiring survey frequency reduction.
71. A — Changed feedwater chemistry or equipment fault affecting corrosion is the most likely cause of new corrosion spots not present before. Chemistry drift, chemical substitution, deaerator problems, or oxygen ingress are all potential causes. Investigation of recent changes leads to the specific source.
72. D — Atomizing medium pressure below specification produces coarse atomization and visible soot despite correct oil temperature. Both atomization pressure and oil temperature must be correct; either failing produces poor combustion. Checking atomizing medium pressure is the diagnostic step.
73. C — Isolating the systems and establishing proper makeup water only is the correct response. Cooling tower blowdown is not appropriate for boiler makeup due to different water chemistry and treatment. The cross-connection must be eliminated to prevent future occurrences.
74. B — Investigating the cause to verify the improvement is the proper operational discipline. A 5% fuel reduction should be explained; unverified improvements can mask meter errors or other

issues. Efficiency changes require systematic verification, not celebration based on apparent results alone.

75. A — Air leak in the pneumatic actuator diaphragm or fittings produces the audible hissing during damper modulation. The actuator may still position correctly but the leak compromises positioning accuracy and wastes control air. Diaphragm replacement or fitting tightening addresses the issue.
76. D — Rotating pumps periodically maintains both in serviceable condition. Letting one run continuously for 6 months while the backup sits idle is poor practice — the backup may fail to start when needed. Alternating pump operation at regular intervals keeps both in service.
77. C — A clogged vent hole prevents the inverted bucket from operating normally. The bucket fills completely with water and remains submerged, unable to cycle. Cleaning the vent hole restores operation. This is a known trap failure mode requiring specific diagnostic knowledge.
78. B — Iron in condensate typically indicates corrosion in condensate return piping from acidic conditions — carbonic acid formed by CO<sub>2</sub> dissolving in condensate. Proper amine treatment prevents this by neutralizing the acid. The iron color is a visual marker of the corrosion process.
79. A — A failed feedwater check valve allows hot boiler water to flow backward through the feedwater system, potentially damaging the pump and cooling feedwater piping. This is the primary failure mode that the check valve is designed to prevent. Valve repair or replacement is typically required.
80. D — A proof-of-closure switch on a fuel valve showing open condition prevents ignition until the valve is confirmed closed. This is a fundamental fuel train safety feature; the BMS cannot permit ignition with unverified valve status. Verifying valve position and position-sensing wiring resolves the issue.
81. C — Heat transfer differences (fouling, scale, or soot) between two otherwise identical boilers explain a 12 percent fuel consumption difference. Both boilers at the same load should consume similar fuel; the difference points to physical condition differences. Comparative inspection identifies the specific cause.
82. A — Operating control setpoint drift below the cut-out value means the controller is keeping pressure below the cut-out, so the boiler is not cycling. Recent gauge calibration rules out gauge drift. Re-verifying and adjusting the setpoint restores proper operation.
83. B — Increased blowdown rate reduces concentration ratio from 5× to 3× by replacing concentrated boiler water with lower-TDS makeup more frequently. This is actually better for equipment life but worse for fuel efficiency. Cause and effect analysis helps understand the trade-off.
84. D — Excessive feedwater demand or water loss somewhere downstream of the deaerator would cause storage level to drop. The deaerator is supplying the feedwater system as designed; the loss

is downstream. Investigation of the feedwater system for leaks or increased demand identifies the source.

85. A — Drift in combustion control causing excess air increase is the most likely cause of falling efficiency with rising O<sub>2</sub>. Combustion controls require periodic tuning; without it, performance gradually degrades. Recalibration and tuning typically restores the lost efficiency.
86. C — Master pressure controller or load-sharing configuration error causes header pressure swings when individual boiler firing rates change. Proper master control stabilizes the header against individual boiler changes. Controller review typically identifies the coordination issue.
87. B — Feedwater supply interruption or pump failure causes rapid water level drop without alarm activation if the failure is recent. The 4-inch drop in 2 minutes is too fast for steam consumption alone. Pump or supply investigation is the first troubleshooting step.
88. D — Winter weather produces cold combustion air inlet temperatures but doesn't produce operational consequences beyond slight efficiency differences. The operator's observation is noting a normal winter condition, not a problem requiring action. Annual fuel consumption typically rises slightly in winter for this reason.
89. A — Boiler efficiency decline from fouled tubes or other causes produces reduced steam output for the same firing rate. The load complaints correlate with this efficiency loss — less steam reaching the process despite apparent normal firing. Efficiency investigation identifies the specific cause.
90. C — Failing steam separator internals in the steam drum produce higher moisture content in the leaving steam. Separators (cyclones, scrubbers, baffles) require periodic inspection and replacement. Normal boiler water level rules out priming as the cause.
91. B — A cutoff operating 10 seconds slower than specification does not meet minimum safety requirements for LWCO response. The cutoff must stop the burner rapidly when water level drops to the cutoff point. Adjustment, cleaning, or replacement is required to restore specified response time.
92. D — Heat loss from equipment, piping, or boiler into the room explains rising boiler room temperature when outdoor conditions are stable. Insulation degradation or increased equipment heat release are typical causes. Investigation of insulation and equipment identifies the specific source.
93. A — An oil preheater not at operating temperature before firing begins is expected during cold-start conditions. The preheater must warm the oil to operating temperature before firing can begin for proper atomization. Waiting for preheat completion is the standard startup practice for heavy fuel oil service.

94. C — Air-fuel ratio control setting that keeps the fan at full speed regardless of firing rate is incorrect. Damper-only modulation without fan speed changes is less efficient and more costly to operate. Proper controls modulate both fan speed and damper position together in metered combustion control.
95. B — Dew-point corrosion from stack gas condensation in the economizer produces uniform tube wall thinning. Economizers operate with cooler surface temperatures where flue gas can condense, producing acidic moisture that corrodes tubes. Uniform pattern across all economizer tubes is diagnostic.
96. A — A failed valve actuator stuck in the fully open position explains the symptom — the regulator cannot respond to control signals and water level climbs. Actuator failure is a typical failure mode requiring replacement. Normal operation would show responsive positioning.
97. D — Systematic root-cause analysis across all three events is the appropriate response to recurring near-misses. Individual analysis misses patterns; accepting or waiting for serious incidents both fail organizational safety. The pattern indicates systemic issues requiring systematic investigation.
98. C — 8 months without calibration is excessive for daily-use analytical equipment. Calibration intervals should be based on manufacturer recommendations and usage patterns, typically 6 months maximum for active instruments. Immediate calibration before further use is the correct action.
99. B — Switching to bypass piping while arranging PRV repair maintains downstream service without emergency conditions. Many pressure-reducing stations include bypass valves specifically for this scenario. Forcing the valve, waiting for natural resumption, or raising upstream pressure all create additional problems.
100. A — Evacuating the affected area and isolating fuel supply at the source is the safe and correct response to a detected gas leak. Continued operation, increasing ventilation as a standalone action, or investigating during operation all risk explosion. Safety must precede investigation.