Codes and Standards Enhancement (CASE) Initiative

2028 California Energy Code

Process Steam

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Executive Summary

This proposal presents updates to process steam requirements for consideration in the 2028 California Energy Code (Title 24, Part 6 or Energy Code). The proposals were developed by the Statewide Codes and Standards Enhancement (CASE) Team to reduce wasteful energy and water use in process steam systems, improve installed system performance, and support California's long-term energy efficiency and greenhouse gas (GHG) reduction goals. The CASE Report evaluates two measures applicable to nonresidential process steam systems: Flash Steam Recovery and Condensate Return.

The Statewide CASE Team developed these proposed measures for submission to the California Energy Commission (CEC) for potential inclusion in the 2028 update to Title 24, Part 6. To be adopted, each measure must be technically feasible and cost effective. The proposed measures focus on recovering useful flash steam from boiler blowdown and increasing condensate return from qualifying indirect-contact process steam loads.

Stakeholder feedback informed the proposed code changes, associated analyses and assumptions, and compliance and enforcement approach. The Statewide CASE Team gathered feedback from manufacturers, sales representatives, maintenance and installation providers, an economic research and consulting firm, an industrial energy benchmarking and consulting firm, steam boiler organizations, Air Quality Management District representatives, and others involved in the code compliance process. The team held two public stakeholder workshops on October 29, 2025 and March 17, 2026, formally interviewed five representatives from three steam boiler organizations and two AQMD representatives, received feedback from three additional representatives via email, and incorporated feedback into proposed code language, exceptions, thresholds, market share estimates, incremental costs, and barriers to adoption.

The Statewide CASE Team recognizes ongoing systemic inequities in environmental and social justice (ESJ) communities and developed the proposals with intentional consideration of potential unintended impacts.

Flash Steam Recovery

Proposed Code Change

This proposed code change would require all newly installed process boilers with capacities at or above 10 million British Thermal Units per hour (MMBtu/h) that are served by a pressurized deaerator to recover and route flash steam from boiler blowdown to the deaerator or another steam load. The requirement would apply to new process boilers, including replacement boilers and boilers installed as part of additions to existing facilities.

Two exceptions would apply: boiler systems where high-pressure condensate is returned to the deaerator without being flashed to atmospheric pressure, and boiler systems where the linear distance from the boiler to the serving deaerator is greater than or equal to 100 feet. Boilers qualifying for an exception would need to document either the pressurized condensate return system or the boiler-to-deaerator distance in construction documents.

Benefits of Proposed Change

The proposed flash steam recovery requirement is expected to save approximately one percent of baseline boiler system fuel consumption in typical steam systems by displacing live boiler steam at the deaerator.

The measure would also reduce water use and water treatment chemicals because flash steam would no longer be vented to the atmosphere and its condensate could be returned to the boiler plant. These reductions would further lower operating costs, and may reduce local photochemical smog, improve air quality, and provide ancillary benefits such as improved plant safety and reduced visible steam plumes.

Compliance and Enforcement

Compliance for the proposed measure would be confirmed during permit application, installation, and inspection by the Authority Having Jurisdiction (AHJ) or building department alongside compliance confirmation of existing requirements for process boilers. To the knowledge of the Statewide CASE Team, compliance and enforcement impacts are feasible and would not add a significant burden when training and education are provided to responsible parties.

Updated NRCC-PRC-E and NRCI-PRC-E fields would document boiler capacity, flash steam recovery routing, installation details, and applicable exceptions. No third-party verification is recommended, and no Alternative Calculation Method Reference Manual or software updates are required.

Market Assessment

Flash steam recovery has been listed in U.S. Department of Energy literature as a best practice since at least the early 2000s, and the market for blowdown flash steam recovery systems is mature. Manufacturers and suppliers provide a range of options for flash steam vessels and piping, and multiple vendors have decades of experience procuring and installing these systems.

While flash steam recovery is well understood among equipment vendors and some designers and contractors, it is not common practice. Industry standard practice is to vent flash steam to the atmosphere and flash steam recovery is often not considered in the design of new construction and retrofit. The Statewide CASE Team estimates that 10 percent of newly added qualifying boiler capacity in California is currently installed with a blowdown flash steam recovery system based on field experience and conversations with boiler system vendors and other stakeholders.

Cost Effectiveness

The proposed code change is highly cost effective across all applicable California climate zones and boiler sizes. Benefit-to-cost ratios (BCRs)[1] range from 8.1 to 222.9 depending on climate zone, boiler size, and annual operating hours.

Incremental first costs include design, equipment, installation, startup, and commissioning. Hardware includes a flash vessel, piping, isolation valves, and a check valve. Incremental maintenance costs are based on piping insulation degradation and periodic insulation repair.

First-Year Statewide Impacts

Table 1: Summary of Statewide Impacts — Flash Steam Recovery

Metric [a]	Total Statewide Impacts
Annual Electricity Savings (GWh)	-
Peak Demand Reduction (MW)	-
Annual Natural Gas Savings (Million Therms)	1.12
Annual Source Energy Savings (Million kBtu)	96.01
30-Year Long-term System Cost Savings (Million 2029 PV$)	$92.27
Annual Avoided GHG Emissions (Metric Tons CO2e/yr)	5,840

a. Values represent impacts from buildings permitted during the first year the code is in effect. Positive values indicate savings or reductions.

Condensate Return

Proposed Code Change

This proposed measure would require all newly constructed process steam loads that use indirect-contact heat exchangers to return all steam condensate to the boiler for

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[1] The benefit-to-cost ratio (BCR) compares benefits or cost savings to costs over the 30-year period of analysis. Proposed code changes with a BCR of 1.0 or greater are cost effective.

reuse through a condensate return system. Qualifying process steam loads would also need to return condensate from associated drip legs. Condensate generated from direct steam injection that directly contacts the process would be exempt.

The proposed measure would apply only to steam loads with reasonably short condensate return distances relative to their steam flow, measured as the linear distance from the steam trap to the nearest condensate return tank or deaerator.

Benefits of Proposed Change

Condensate return is a widely accepted best practice for steam systems. Returning condensate to the boiler system reduces the fuel needed to preheat fresh make-up water and reduces boiler blowdown losses because returned condensate has fewer dissolved solids.

In addition to energy savings, this measure may also reduce water use, water treatment chemicals, and local photochemical smog from boiler combustion.

Compliance and Enforcement

Compliance for this measure would be confirmed through plan review, installation, and inspection of new steam loads by the Authority Having Jurisdiction (AHJ) or building department. New fields would be added to the Process Systems Certificate of Compliance form NRCC-PRC-E and Process System Certificate of Installation form NRCI-PRC-E to record plan review and inspection.

No third-party verification is recommended, and no compliance software updates are identified. To the knowledge of the Statewide CASE Team, the proposed compliance and enforcement steps for this measure are feasible and would not present a significant burden when training and education are provided to responsible parties.

Market Assessment

Condensate recovery systems are commonly included in steam system designs, and steam and boiler system designers are familiar with these systems. Components such as piping, pumps, and condensate return tanks are available as packaged systems or individual components from multiple manufacturers and suppliers.

Despite the fuel, chemical, water, and wastewater savings, many industrial facilities do not install condensate return systems because of the upfront installation cost. Stakeholder interviews indicated condensate return rates vary widely by industry and application. Based on these interviews and field experience at industrial sites, the Statewide CASE Team estimates that 30 percent of total steam flow is returned across new qualifying statewide steam capacity in California today.

Cost Effectiveness

The proposed code change is cost effective across all applicable California climate zones and boiler sizes. Benefit-to-cost ratios range from 6.6 to 21.0 depending on climate zone, boiler size, and annual operating hours.

Incremental first costs include purchase and installation of condensate return piping, piping insulation, condensate tank, and condensate pumps. Maintenance and replacement costs include insulation maintenance and pump replacement every 10 years, and tank replacement in year 20.

First-Year Statewide Impacts

Table 2: Summary of Statewide Impacts — Condensate Return

Metric [a]	Total Statewide Impacts
Annual Electricity Savings (GWh)	0.00
Peak Demand Reduction (MW)	0.00
Annual Natural Gas Savings (Million Therms)	2.25
Annual Source Energy Savings (Million kBtu)	192.88
30-Year Long-term System Cost Savings (Million 2029 PV$)	$186.30
Annual Avoided GHG (Metric Tons CO2e/yr)	11,731

a. Values represent impacts from buildings permitted during the first year the code is in effect. Positive values indicate savings or reductions.

Acronyms

Table 3 presents a list of acronyms used in this report. Title24stakeholders.com also maintains a glossary of terms.

Table 3: List of Acronyms

Acronym	Definition
ACM	Alternative Calculation Method
ADA	Americans with Disabilities Act
AHJ	Authority Having Jurisdiction
APCD	Air Pollution Control District
AQMD	Air Quality Management District
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
ASME	American Society of Mechanical Engineers
ATT	Acceptance Test Technician
BCR	Benefit-to-Cost Ratio
BEA	Bureau of Economic Analysis
BEM	Building Energy Modeling
Btu	British Thermal Units
CAGR	Compound Annual Growth Rate
CALGreen	California Green Building Standards Code
CARB	California Air Resources Board
CASE	Codes and Standards Enhancement
CBSC	California Building Standards Commission
CBECC	California Building Energy Code Compliance Software
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CBO	Community-Based Organization
CO_2e	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
CSE	California Simulation Engine
CTF	Conduction Transfer Functions
CZ	Climate Zone
DAC	Disadvantaged Community
DEER	Database of Energy Efficiency Resources
DGS	California Department of General Services
DOAS	Dedicated Outdoor Air System

DOE	Department of Energy
DOSH	Division of Occupational Safety and Health
ECC	Energy Code Compliance
EIR	Environmental Impact Report
EPIC	Electric Program Investment Charge
ESJ	Environmental and Social Justice
EUL	Effective Useful Life
F	Fahrenheit
FGR	Flue Gas Recirculation
FRED	Federal Reserve Economic Data
FSOR	Final Statement of Reasons
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt-Hour
HVAC	Heating, Ventilation, and Air Conditioning
IAC	Industrial Assessment Center
IDF	Input Data File
IECC	International Energy Conservation Code
IOU	Investor-Owned Utility
IPGR	Industrial Production Growth Rate
ISOR	Initial Statement of Reasons
kBtu	Thousand British Thermal Units
kBtu/yr	Thousand British Thermal Units Per Year
Kg/s	Kilograms Per Second
kWh	Kilowatt-Hour
kWh/year	Kilowatt-Hour Per Year
lb/h	Pounds Per Hour
lbm	Pound-mass
LF	Linear Foot
LMI	Low- and Moderate-Income
LPD	Lighting Power Density
LSC	Long-term System Cost
MeasureSET	CASE Measure Savings Estimation Template
MG	Million Gallons of Water
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units Per Hour
NA9	Non-Residential Reference Appendix 9

NAICS	North American Industry Classification System
NIST	National Institute of Standards and Technology
NOx	Nitrogen Oxides
NPDI	Net Private Domestic Investment
NR	Nonresidential
NRCA	Nonresidential Certificate of Acceptance
NRCC	Nonresidential Certificate of Compliance
NRCI	Nonresidential Certificate of Installation
OEM	Original Equipment Manufacturer
OSHA	Occupational Safety and Health Administration
PEP	Public Engagement Plan
ppmv	Parts Per Million by Volume
psig	Pounds Per Square Inch Gauge
PV	Present Value
RO	Reverse Osmosis
SCR	Selective Catalytic Reduction
SDD	Standards Data Dictionary
SOC	Standard Occupational Classification
SPMS	Saturation Pressure Measurement Sensors
SRIA	Standardized Regulatory Impact Assessment
TDS	Total Dissolved Solids
UL	Underwriters Laboratories
W	Watt
μΩ	Micro-ohm

1. Introduction

1.1 Report Context

This proposal describes specific energy efficiency code changes (referred to as “measures”) aimed at reducing wasteful, uneconomic, inefficient, or unnecessary energy consumption in California. These measures are submitted to the California Energy Commission (CEC) for consideration and potential inclusion in California’s Energy Code (Title 24, Part 6), which sets statewide energy efficiency requirements for newly constructed buildings and for additions and alterations to existing buildings. Measures may also be considered for inclusion in California Green Building Standards Code, known as CALGreen (Title 24, Part 11), as voluntary energy efficiency standards, which would take effect only if adopted by a local jurisdiction seeking to exceed the minimum requirements of the Energy Code. Measures submitted to the CEC will be reviewed and may be modified or incorporated into a broader regulatory package proposed and adopted by the CEC. To be included in the Energy Code, proposed measures must be both cost effective and technically feasible.

1.2 Proposal Sponsors

Three California Investor-Owned Utilities (IOUs)—Pacific Gas & Electric Company, San Diego Gas & Electric, and Southern California Edison jointly sponsored this effort. Where the term “Statewide CASE Team” is used in this report, it refers to the authors and State Building Codes Advocacy activities supported through the Codes and Standards program.

1.3 Stakeholder Engagement to Inform Proposal

When developing the code change proposal and associated technical information presented in this report, the Statewide CASE Team worked with or gathered feedback from many industry stakeholders including manufacturers, sales representatives, maintenance and installation providers, an economic research and consulting firm, an industrial energy benchmarking and consulting firm, and others involved in the code compliance process. The proposal incorporates feedback received during two public stakeholder workshops that the Statewide CASE Team held on October 29, 2025 and March 17, 2026. Materials from the workshops are available at title24stakeholders.com (Swanson, et al., Process Steam #1: Flash Steam Recovery, 2025; Swanson, et al., Process Steam #2: Condensate Return, 2025; PG&E, SDG&E, SCE, LADWP, and SMUD, 2025)

The Statewide CASE Team engaged with multiple steam boiler manufacturers, representatives, and industry stakeholders to learn more about current industry trends and practices across the proposed measures. The Statewide CASE Team had formally interviewed five representatives from three steam boiler organizations and two representatives from Air Quality Management Districts (AQMDs) and received feedback from three additional representatives via email. The interviews covered topics including boiler lifespan, efficiency, and current industry practices related to flash steam recovery and condensate return. These interviews informed this report's estimates for the current commercial landscape of this equipment, including the market share, incremental costs, and barriers to adoption of equipment necessary to comply with the proposed measures. The Statewide CASE Team shared specific details of the proposed measures with interviewees, including planned measure exceptions and requirement thresholds, and received feedback from those stakeholders that was subsequently incorporated into the proposed code language discussed in this report.

See Appendix E for details on the Statewide CASE Team's stakeholder engagement.

1.4 Addressing Energy Equity and Environmental Justice

The Statewide CASE Team recognizes, acknowledges, and accounts for a history of prejudice and inequality in environmental and social justice (ESJ) communities.[2] These issues persist today. To minimize the risk of perpetuating inequity, code change proposals were developed with intentional consideration of the unintended consequences on ESJ communities.

When analyzing impacts for nonresidential buildings, the Statewide CASE Team reviewed each nonresidential building type through the lens of the four criteria: cost, health, resiliency, and comfort. The Statewide CASE Team examined which building types are used by ESJ communities most frequently and evaluated the allocation of impacts related to the following areas among all populations. Some building types have unique environmental justice concerns due to their common uses, location, or other factors.

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[2] The CPUC refers to ESJ communities as "low-income or communities of color that have been underrepresented in the policy setting or decision-making process, are subject to a disproportionate impact from one or more environmental hazards, and likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities" (CPUC 2022). ESJ communities also include the CPUC definition for Disadvantaged Communities, which comprises "(1) Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts); (2) Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts); (3) Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (307 tracts); and (4) Lands under the control of federally recognized Tribes (OEHHA 2022).

The Statewide CASE Team will continue to build relationships with CBOs and other stakeholders to improve the identification of potential impacts for future code cycles and is open to additional resources that can contribute to this effort.

2. Flash Steam Recovery

2.1 Flash Steam Recovery – Measure Description

2.1.1 Proposed Code Change

A process boiler is a type of boiler with a capacity (rated maximum input) of 300,000 British Thermal Units per hour (Btu/h) or more that serves loads other than space conditioning and service water heating related to human occupancy.

This proposed code change would require all newly installed process boilers, including new replacement boilers, with capacities at or above 10 million Btu/hour (MMBtu/h) that are served by a pressurized deaerator to recover and route flash steam from blowdown to the deaerator or another steam load. The requirement would apply to all new process boilers, including replacement boilers and boilers installed as part of additions to existing facilities.

There are two proposed exceptions to the requirement:

1. Boiler systems where high-pressure condensate is returned to the deaerator without being flashed (dropped to atmospheric pressure).
2. Boiler systems where the linear distance (sum of horizontal and vertical) from the boiler to the serving deaerator is greater than or equal to 100 feet.

All boilers qualifying for one of the exceptions must indicate either the installation of a pressurized condensate return system or the linear distance from the boiler to the serving deaerator in the construction documents according to the exception they are pursuing.

Table 4 summarizes the scope of the proposed code change.

Table 4: Scope of Proposed Code Change

A ☑ indicates the proposed code change is relevant.

Building Type(s)	Construction Type(s)	Type of Change
☐ Single Family	☑ New Construction	☑ Mandatory
☐ Multifamily	☑ Additions	☐ Prescriptive
☑ Nonresidential (excluding Occupancy R uses)	☑ Alterations	☐ Performance

Application Climate Zones	Energy Code Sections	Compliance Forms	Sections of ACM Reference Manuals
Climate Zones 1-16	Part 6, Sections 201 and 904.1	NRCC-PRC-E NRCI-PRC-E	N/A

Third Party Verification	Updates to Compliance Software
☑ No changes to third party verification	☑ No updates
☐ Update existing verification requirements	☐ Update existing feature
☐ Add new verification requirements	☐ Add new feature

2.1.2 Benefits of Proposed Change

When applied in typical steam systems, the proposed flash steam recovery requirement is expected to save approximately one percent of baseline boiler system fuel consumption. The fuel savings from flash steam recovery result from a decrease in required fuel combustion when flash steam displaces live boiler steam at the deaerator.

Flash steam recovery also reduces water use and the chemicals used for water treatment, as the flash steam is no longer vented to the atmosphere and its condensate can be returned to the boiler plant for reuse. The reductions in fuel, water, and chemical use result in operating cost savings for steam system owners and operators.

In addition to providing energy and water benefits, these practices may reduce local photochemical smog and improve air quality. The value of improved air quality is amplified by the consideration that industrial facilities are disproportionately located near Low- and Moderate-Income (LMI) housing. Ancillary benefits may also include improved plant safety and market support for flash steam recovery equipment. Finally, reduced steam venting provides an aesthetic benefit for people who live near industrial facilities and associate steam plumes with pollution.

2.1.3 Background Information

When steam condensate is dropped to a pressure lower than its saturation (boiling-point) pressure, a fraction of it vaporizes, or flashes, into what is known as flash steam. The higher the temperature and pressure of the condensate, the more flash steam is generated when it is lowered in pressure. Most sites vent flash steam to the atmosphere, resulting in significant fuel, water, and chemical losses from the steam system. Flash steam recovery vessels, also called flash tanks, are used to recover flash steam and reroute it to lower pressure loads such as the deaerator for useful heating, which displaces use of live boiler steam. Recovery of this flash steam reduces the amount of steam vented to the atmosphere and saves fuel, water, and chemicals.

A blowdown flash steam recovery system consists of a pressurized flash steam recovery vessel, labeled insulated piping, isolation valves, and a check valve. Without a flash steam recovery system, existing sites would already have an atmospheric flash tank in place, which would be replaced by the pressurized flash steam recovery vessel in most cases.

Flash steam recovery has been listed in U.S. Department of Energy (DOE) literature as a best practice since at least the early 2000s, and DOE has published five steam tip sheets for different flash steam recovery methods. This proposed code change originated from discussions with California-based consulting engineers from strategic energy management programs and the DOE Industrial Assessment Center program.

General factors that affect the success of flash steam recovery and the benefits of flash steam recovery from boiler blowdown include the following:

- Stability of supply and demand: Economic viability improves when a load can supply a consistent and reliable mass flow of flash steam and when the demand for flash steam is a continuous, lower-pressure load. Intermittent supply loads are less desirable for flash steam recovery. To save energy, the use of the supplied flash steam must displace live boiler steam or another form of fuel use.
    - As boilers operate continuously, boiler blowdown provides a stable supply of flash steam. Deaerators operate constantly and provide a consistent demand for heat.
- Proximity of supply and demand: It is preferable for the flash steam to be used near its source. Lower-pressure steam, such as flash steam, requires larger pipe diameters to minimize pressure drop and velocity, which increases project cost when the flash steam must be transported long distances.
    - Deaerators are typically located in the same boiler room as the boiler, allowing for short piping lengths. However, if one deaerator serves multiple boilers, the distance from the farthest boiler to the deaerator could be longer.

To ensure cost-effectiveness of this measure, this proposed requirement would only apply to systems that have larger boilers (at and above 10 MMBtu/h), which provide a continuous supply of blowdown flash steam, and that have pressurized deaerators, which provide a continuous heating load. The proposed requirement also has an exception for boiler systems where the linear distance from the boiler to the serving deaerator is greater than or equal to 100 feet. While sites may choose to route recovered flash steam to alternative heating loads in addition to deaerator heating, routing recovered boiler blowdown flash steam to the deaerator provides a constant and cost-effective compliance pathway.

2.1.4 Modifications to Energy Code Documents

This section provides descriptions of how the proposed code change will affect each Energy Code document. See Section 2.6 of this report for detailed revisions to code language.

2.1.4.1 Energy Code Change Summary

SECTION 100 – SCOPE AND ADMINISTRATION

Subsection 100.4: Updated section names in Table 100.4-B [Table 100.0-A] Application of Standards Covered Processes.

SECTION 200 – DEFINITIONS AND RULES OF CONSTRUCTION

Subsection 201: The proposed measure would add new definitions for flash steam and pressurized condensate return.

SECTION 904 – PROCESS BOILERS (NEWLY CONSTRUCTED, ADDITIONS, ALTERATIONS)

Subsection 904.1.4: The proposed measure would add a requirement for newly installed process boilers with capacities at or above 10 million British Thermal Units per hour (MMBtu/h) that are served by a pressurized deaerator to recover and route flash steam from blowdown to the deaerator or to another heating load. Two exceptions would exempt boiler systems with high-pressure condensate return and boiler systems where the linear distance from the boiler to the serving deaerator is greater than or equal to 100 feet.

2.1.4.2 Reference Appendices Change Summary

The proposed measure will not modify the reference appendices because there is no functional testing required for compliance verification.

2.1.4.3 Compliance Manuals Change Summary

The proposed changes would include updates to Section 10.9.2 of the Nonresidential Compliance Manual, which outlines mandatory requirements for process boilers. A newly created subsection would explain the flash steam recovery requirement and verification.

2.1.4.4 Alternative Calculation Method Reference Manual Change Summary

The proposed measure will not modify Alternative Calculation Method (ACM) Reference Manuals because the proposed measure requires no associated software updates.

2.1.4.5 Compliance Forms Change Summary

The existing Process System Certificate of Compliance form (NRCC-PRC-E, Section I: Process Boilers) would require updated input fields to capture boiler capacity ratings that trigger compliance requirements. In addition, a new input field would be added to document whether the process steam boiler system recovers and routes flash steam from boiler blowdown to the deaerator or another heating load, along with verification of any applicable exceptions. The Process System Certificate of Installation form (NRCI-PRC-E, Process Boilers) would be updated with corresponding input fields to confirm that qualified boilers meet the flash steam recovery requirements, as specified in the NRCC-PRC-E. Additional fields would be included to document installation details of the flash steam recovery system, including flash tank overhead piping and confirmation that required piping and valves are installed and open.

2.1.5 Measure Context

2.1.5.1 Comparable Model Codes or Standards

Review found no relevant and comparable model codes or standards for context.

2.1.5.2 Interactions with Other Regulations

The Statewide CASE Team found no known existing federal, state, or local regulatory requirements that address flash steam recovery in process steam boiler systems. Current Title 24, Part 6 requirements cover steam traps in new industrial facilities and steam traps added to support new, non-replacement process equipment in existing industrial facilities where the installed steam trap operating pressure is greater than 15 psig and the total combined connected boiler input rating is greater than 5 MMBtu/h. The code requires central steam trap fault detection and diagnostics monitoring, steam trap fault detection, and steam trap strainer installation. The proposed requirement for flash steam recovery would have no impact on these existing requirements.

While the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) does not have a specific standard for flash steam recovery, the ASHRAE Handbook *HVAC Systems and Equipment* and the ASHRAE *Fundamentals of Steam System Design* have application guidance for flash steam recovery (ASHRAE, 2020; ASHRAE, 2006).

Review finds no known interactions with other parts of the California Building Code or local requirements. The proposed requirement would not interfere with compliance with

Occupational Safety and Health Administration (OSHA) requirements for pressurized vessels. Only pressurized flash steam recovery vessels operating at 15 psig or would be subject to OSHA requirements for pressurized vessels. Nearly all blowdown flash steam recovery vessels installed to comply with the proposed requirement would operate below 15 psig and therefore not be subject to OSHA requirements for pressurized vessels.

The proposed requirement would not interfere with AQMD requirements related to boiler emissions because the AQMDs do not regulate water vapor emissions. By reducing overall boiler combustion emissions, the proposed requirement will support AQMD air quality goals in the state of California.

2.2 Flash Steam Recovery – Compliance and Enforcement

2.2.1 Compliance Considerations

When developing this proposal, the Statewide CASE Team considered methods to streamline the compliance and enforcement process and how negative impacts on market actors who are involved in the process could be mitigated or reduced. The Statewide CASE Team believes that compliance and enforcement of the proposed measure is feasible and would not add significant compliance or enforcement burden to those responsible for ensuring compliance with building code when training and education on requirements is provided.

To ensure compliance with the proposed flash steam recovery requirement, confirmation steps would need to be taken during permit application (plans review), installation, and inspection by the Authority Having Jurisdiction (AHJ) or building department. New fields in the Process Systems Certificate of Compliance Form NRCC-PRC-E and the Process System Certificate of Installation form NRCI-PRC-E would need to be completed.

Designers: Designers would need to be aware that requirements for process boilers in section 904.1 have been expanded, enabling design compliant process boiler systems. They would need to fill out an updated NRCC-PRC-E form and to submit design documents indicating a compliant design. For boilers pursuing an exception, either the installation of a pressurized condensate return system or the linear distance from the boiler to the serving deaerator should be clearly outlined in the construction documents according to the exception they are pursuing.

AHJ plan checkers: During the permit application phase, AHJ plan checkers would review the submitted NRCC-PRC-E form and design documents to confirm that the design includes a blowdown flash steam recovery system or qualifies for a claimed exception based on the planned installation of a pressurized condensate return system or the linear distance from the boiler to the serving deaerator.

Installation contractors: Installation contractors would be required to correctly install blowdown flash steam recovery systems in accordance with design and manufacturing specifications and OSHA requirements, which is already required as part of normal operating procedures. The installation contractors will document the installation in the NRCI-PRC-E form unless done by another party. When the installation contractor fills in the Certificate of Installation form, they would need to include the model number of the flash steam recovery vessel.

Field technicians: Field technicians are typically the installers or technicians configuring the boiler system controls and are not certified Acceptance Testing Technicians (ATT). Field technicians may complete the flash steam recovery fields in the process boilers section of the NRCI-PRC-E form if the installation contractors do not complete them. For sites claiming no exemption, compliance verification includes confirmation of flash steam recovery system installation. Field technicians would need to understand these different code and testing requirements for exempt and non-exempt sites. Sites seeking to reduce compliance burdens can have the commissioning technicians who tune the equipment prior to AQMD-required stack testing also confirm installation of a flash steam recovery system.

AHJ building inspectors: In addition to the process boiler inspection items already required for a new boiler installation, the AHJ building inspector would need to verify installation of a blowdown flash steam recovery system in the NRCI-PRC-E form. Review finds that all definitions added for the new proposed code language do not conflict with any existing definitions in other parts of Title 24.

2.2.2 Impact on Market Actors

Table 5 summarizes actors and suggests outreach and education that might be helpful to support market actors as they prepare for the effective date of the requirements.

Table 5: Impacts on Market Actors and Suggested Training and Education Opportunities

Market Actor	Impact(s)	Suggested Outreach and Education
Owner/Operator[a]	Be aware that blowdown flash steam recovery is required and plan for additional costs. Expect higher upfront cost and reduced energy and water bills. Expect to maintain flash steam recovery equipment. May need to complete the NRCC-PRC-E form for replacement boilers at existing facilities.	Outreach to owners and operations personnel could improve understanding of the benefits of flash steam recovery. Additional training could reinforce the importance of piping insulation maintenance.
Design Professional[b]	When designing process steam boiler systems, design professionals should be aware of new requirements for flash steam recovery from boiler blowdown, understand what triggers the requirement, and include flash steam recovery equipment specifications in design documents. Complete new fields of NRCC-PRC-E Process Boilers section.	Industrial process steam design firms should be provided with training on updates to the energy code requirements and compliance documentation.
Construction Team[c]	Install a blowdown flash steam recovery system as specified in the approved design documents, consistent with standard practice. Complete fields in the Process Boilers section of NRCI-PRC-E.	System installers should be provided training on the energy code updates and supporting documentation, compliance requirements, and compliance documentation.
Building Department[d]	Plan Reviewers will have an additional requirement to check when reviewing NRCC form and design documents.	Provide education and training to local building department plans examiners to familiarize themselves with new code language.
Verification Tester[e]	No verification testing is required.	N/A
Manufacturers and Distributors	Additional sales of flash steam recovery equipment.	Additional training likely unnecessary.

a. Owner/Operator is funding the project and is the primary decision-maker.

b. Design professionals include architects, engineers (mechanical, electrical, plumbing, structural), specification writers, cost estimators, commissioning agents, lighting designers, and energy consultants.

c. Construction team includes general contractors, design-build contractors, installation contractors (e.g., HVAC, plumbing, electrical), commissioning agents, and tradespeople.

d. Building departments include plan reviewers, building inspectors, specialty inspectors, permit counter technicians, and third-party plan review and inspection.

e. Verification testers include commissioning agents, Energy Code Compliance Raters, and Acceptance Test Technicians.

The 2028 CASE Methodology Report presents a quantitative assessment of how changes to the California Building Code impact builders, building designers, and energy consultants. While the analysis in the methodology report is not specific to the code changes presented in this report, this measure focuses on industrial facility owners and operators, design and installation professionals, and building department representatives, since these market actors are expected to experience the most direct impacts from the proposed flash steam recovery measure. The following section provides a qualitative description of how this specific code change affects various market actors, along with additional quantitative analyses of its potential impacts on building industry subsectors.

Building owners. The proposed code change would have incremental costs and would reduce building owners' utility bills throughout the measure's lifetime. See the 2028 CASE Methodology Report for a description of how LSC savings relate to occupant utility bill savings.

Builders. The proposed change would likely affect industrial builders; however, it would likely not impact firms focused on the construction or retrofitting of residential buildings, utility systems, or public infrastructure. The proposed change would not affect all firms and workers in the industrial and commercial building industries equally; instead, it would primarily affect specific subsectors within the industries. Table 6 shows the construction subsectors that the Statewide CASE Team expects will be impacted by the changes proposed in this report.

Table 6: Specific Subsectors of the California Commercial and Industrial Building Industries Impacted by Proposed Change to Code by Subsector in 2029 (Estimated)

Construction Subsector	Establishments*	Employment	Annual Payroll (Billions $)
Industrial Building Construction	278	4,095	$0.5
Nonresidential Structural Steel Contractors	365	11,899	$1.1
Nonresidential Plumbing & HVAC Contractors	2,270	55,182	$5.8
Other Nonresidential Equipment Contractors	580	9,749	$1.1
Nonresidential Site Preparation Contractors	1,147	19,273	$1.9
All Other Nonresidential Trade Contractors	948	17,084	$1.7

Source: (State of California, n.d.)

*An establishment is a single economic unit, typically at one physical location, that engages in one, or predominantly one, type of economic activity for which a single industrial classification may be applied. Many businesses are composed of multiple establishments. US Bureau of Labor Statistics, Handbook of Methods. https://www.bls.gov/opub/hom/cew/concepts.htm

Manufacturers. Multiple manufacturers and installers of flash steam equipment operate in California, and these businesses would sell and install components of flash steam recovery systems. Refer to Section 2.3.1.1 for further discussion of these manufacturers and installers and Section 2.3.4 for more information on the resultant impact on California jobs.

2.2.3 Compliance Software Updates

Review finds no compliance software updates required for this measure proposal.

2.2.4 Cost of Enforcement

The Statewide CASE Team acknowledges that changes to the code will impact enforcement costs. This report is an evaluation of specific measures, and the collective impact of all proposed changes for 2028 Title 24, Part 6 may represent an increase in training and/or workload for enforcement personnel. The cost of enforcement would include the cost of delivering training to enforcement officials to enable them to adequately enforce the proposed measure. This training can leverage current education programs to minimize expenses. Local governments will need to retrain building department staff; however, this practice aligns with the regular triennial code update cycle and is supported by resources such as Energy Code Ace.

The enforcement costs would also include the costs of plan review and inspection. During plan review, the plan examiners would review the Process Boilers section of the NRCC-PRC-E and ensure that the energy features and performance specifications, materials, components, and manufactured devices for the system design identified on the form conform to the requirements of Title 24, Part 1 and Part 6 of the California Code of Regulations and are consistent with the drawings and specifications. Building inspectors would need to verify compliance with one additional requirement for Process Boilers in the NRCI-PRC-E form and ensure that the information on the form is consistent with the approved NRCC-PRC-E forms and with what is actually installed.

2.3 Flash Steam Recovery – Market and Economic Analysis

2.3.1 Market Structure and Availability

2.3.1.1 Current Market Structure and Availability

Participants in the market for blowdown flash steam recovery system equipment include steam system designers, component manufacturers, OEMs, steam system equipment manufacturers, manufacturer representatives, distributors, mechanical contractors, and service technicians. Designers specify blowdown flash steam recovery systems, ensuring proper component sizing and identifying the best low-pressure applications for recovered steam. Component manufacturers and OEMs design, manufacture, and supply the system components—traditionally piping, flash recovery vessels, and valves—both as packaged systems and as individual components. Manufacturer representatives and distributors act as the local sales and distribution channels for component manufacturers and specialized steam equipment companies. Mechanical contractors manage the physical installation of the system. Equipment manufacturer representatives and mechanical contractors typically perform startup and commissioning.

The Statewide CASE Team surveyed manufacturer websites in October 2025 and confirmed that manufacturers and suppliers provide designers and contractors with numerous options for flash steam recovery vessels and piping. The flash steam market has proven supplier stability and reliability, as flash steam products have been available in manufacturer catalogs for decades (Armstrong International, 2011). Multiple vendors and suppliers have extensive experience procuring and installing blowdown flash steam recovery systems, confirming a mature and well-established market. Table 7 lists companies that the Statewide CASE Team has identified as major market actors.

Table 7: Major Flash Steam Recovery Market Actors

Company	Market Actor Type	Product Offering	Headquartered in California
Armstrong	Manufacturer	Flash vessel	No
A Louis Supply	Distributor	Flash vessel	No
Didion Vessel LLC	Manufacturer	Flash vessel	No
Calpacific Equipment Company	Vendor	Flash vessel (Madden Engineered Products)	Yes
PVV Corp	Manufacturer	Flash vessel, piping	Yes
Spirax Sarco	Manufacturer	Flash vessel	No
Watson McDaniel	Manufacturer	Flash vessel	No

The Statewide CASE Team believes that steam and boiler system designers are familiar with flash steam recovery systems but will likely require training on code updates to ensure boiler and steam system designs meet the proposed code requirements. Major steam equipment vendors are typically familiar with flash steam recovery, and some vendors have application engineers with flash steam recovery expertise. Most mechanical contractors are aware of the basic application that would be required for measure compliance.

The Statewide CASE Team estimates that 10 percent of newly added qualifying boiler capacity in California is installed with flash steam recovery systems, based on field experience in California and stakeholder feedback from a public stakeholder workshop that the Statewide CASE Team held on October 29, 2025. The Statewide CASE Team does not foresee that the proposed requirement would have any negative impacts on technology adoption.

2.3.1.2 Market Challenges and Solutions

Flash steam recovery is not common practice, but flash steam recovery from boiler blowdown is well understood among equipment vendors and some designers and contractors. Rerouting flash steam from boiler blowdown for deaerator heating is the most common application of flash steam recovery.

Many sites continue to vent all flash steam to the atmosphere, as venting flash steam is industry standard practice and flash steam recovery is not considered when planning boiler systems. Facilities that consider flash steam recovery may decline to implement it due to the upfront planning, cost, and implementation burden of flash steam recovery systems and the small energy savings relative to overall facility energy use.

The presence and stability of low-pressure steam loads where recovered flash steam can be used varies between facilities. To ensure that the site has at least one low-pressure steam application available for recovered flash steam, the proposed flash steam recovery requirement would only apply to facilities with a pressurized deaerator. This criterion was added based on input from a boiler systems manufacturer during a stakeholder interview.

Though rare, some steam system designs use pressurized condensate return systems. These systems maintain recovered condensate above atmospheric pressure throughout the recovery process, which reduces the generation of flash steam and allows flash steam to be piped back to the deaerator. For systems with pressurized condensate return, blowdown flash steam recovery would be less cost-effective due to the lower quantity of available flash steam and the possible need for higher-cost flash vessels designed for higher pressures. Therefore, the proposed code change includes an exception for boiler systems with pressurized condensate return, which already recover significant flash steam energy.

2.3.2 Design and Construction Practices

2.3.2.1 Current Design and Construction Practices

Industry widely accepts flash steam recovery as a best practice. DOE has developed five steam tip sheets that discuss the benefits of recovering flash steam and several potential recovery methods, including recovering flash steam from boiler blowdown (DOE, 2012). Blowdown flash steam recovery systems primarily consist of a flash vessel and piping. Flash vessels are American Society of Mechanical Engineers (ASME)-stamped pressure vessels that separate condensate from flash steam (Wessels Company, n.d.). The vessels are offered in vertical and horizontal configurations, with the vertical orientation providing for better separation of flash steam and condensate (National Institute of Health, 2023). When designing a blowdown flash steam recovery system, designers must calculate the design condition blowdown flow rate, select a flash vessel size for that flow rate, and size the flash steam piping to limit the steam velocity leaving the vessel. Flash vessel manufacturers often assist designers in selecting vessels. Proper vessel selection and pipe sizing prevent carryover of liquid droplets into the flash steam piping (wet steam), which can accelerate fouling and erosion and reduce the useful life of the equipment and its lifetime energy savings.

2.3.2.2 Health and Safety Considerations

The proposed code change would increase the quantity of on-site piping that is lightly pressurized and carrying steam. The proposed change does not alter any existing federal, state, or local safety and health regulations, including those enforced by the California Division of Occupational Safety and Health (DOSH). All existing health and safety rules would remain in place. Facility staff and those involved with the construction, commissioning, and maintenance of the site would not experience any adverse impacts on safety or health associated with the proposed code change. The proposed code change would reduce photochemical smog and improve air quality near the facility by reducing boiler fuel consumption and associated emissions.

2.3.2.3 Design and Construction Challenges and Solutions

The Statewide CASE Team identified two potential design and construction challenges for flash steam recovery systems: 1) limited applications for recovered flash steam, and 2) long distances between recovery and use that require long pipe runs.

When designing flash steam recovery systems, designers must consider the size and stability of low-pressure loads to which the recovered flash steam can be applied. The Statewide CASE Team developed the proposed code language for this measure to include flexibility in the choice of flash steam-recovery application. Additionally, the proposed requirement would apply only to steam systems with pressurized deaerators, ensuring that the system has at least one constant source of low-pressure steam demand via deaerator heating.

The distance of pipe runs between the source and application of recovered flash steam may vary between sites. However, boiler deaerators are typically located in the same room as the boiler they serve, ensuring that flash steam recovery pipe runs will not be unduly long at qualifying sites. Boiler systems where the linear distance from the boiler to the serving deaerator is greater than or equal to 100 feet are exempt from the requirement to ensure that no sites are required to implement a flash steam recovery system that is not cost-effective. See Section 2.2 for a description of workforce trainings that may be needed to ensure effective design, installation, and commissioning.

2.3.3 Energy Equity and Environmental Justice

Each measure in this CASE Report was evaluated for ESJ impacts using 4 criteria: cost, health, resiliency, and comfort. The details of that evaluation can be found in Section 1.4 and the 2028 CASE Methodology Report.

The Statewide CASE Team does not expect any impact on the health and safety of ESJ communities, or on their disaster preparedness. The comfort of ESJ communities is unlikely to be impacted by the proposed code changes.

The use of flash steam recovery in boiler systems would reduce boiler fuel consumption and avoid the associated emissions from burning fuel. The value of improved air quality from the proposed code changes is augmented by the fact that industrial facilities are disproportionally located near ESJ and Low- and Moderate-Income (LMI) housing. As a result, the Statewide CASE Team expects that ESJ communities may experience a disproportionate air quality improvement over time from this proposed measure.

2.3.4 Impacts on Jobs and Businesses

The Statewide CASE Team does not anticipate significant employment or financial impacts on any particular sector of the California economy from this proposed measure. However, the proposed change may have modest impacts on employment in California. The Statewide CASE Team anticipates that the proposed change would directly and indirectly affect statewide employment and economic output through its impact on builders, designers, energy consultants, and building inspectors. Table 8, Table 9, and Table 10 outline the statewide implications for these job categories. For more information on the Statewide CASE Team's economic impacts methodology, see the 2028 CASE Methodology Report.

The Statewide CASE Team does not anticipate that the proposed changes would lead to the creation of new types of jobs or the elimination of existing types of jobs. In other words, the Statewide CASE Team's proposed change would not result in economic disruption to any sector of the California economy. Rather, it would lead to modest increases in the employment of existing jobs.

Table 8: Estimated Impact that Adoption of the Proposed Measure would have on the California Nonresidential Construction Sector

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by commercial builders)	8.9	$710,130	$1,069,172	$2,313,363
Indirect Effect (Additional spending by firms supporting commercial builders)	5.2	$410,487	$704,715	$1,233,759
Total Economic Impacts	**14.1**	**$1,120,617**	**$1,773,887**	**$3,547,122**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.[3]

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[3] IMPLAN® model, 2020 Data, IMPLAN Group LLC, IMPLAN System (data and software), 16905 Northcross Dr., Suite 120, Huntersville, NC 28078 www.IMPLAN.com

Table 9: Estimated Impact that Adoption of Proposed Measure would have on California Building Designers and Energy Consultant Sectors

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by building designers and energy consultants)	0.2	$19,942	$19,742	$31,204
Indirect Effect (Additional spending by firms supporting building designers and energy consultants)	0.1	$5,938	$8,252	$13,284
Total Economic Impacts	**0.3**	**$25,879**	**$27,994**	**$44,489**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.

Table 10: Estimated Impact that Adoption of the Proposed Measure would have on California Building Inspectors

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by building inspectors)	0	$2,707	$3,210	$3,901
Indirect Effect (Additional spending by firms supporting building inspectors)	0	$251	$390	$680
Total Economic Impacts	**0**	**$2,958**	**$3,601**	**$4,581**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.

The proposed change represents a modest adjustment, which is not expected to excessively burden or competitively disadvantage California businesses, nor is it expected to lead to a competitive advantage for California businesses. Therefore, the Statewide CASE Team does not expect the proposed code changes to result in the creation of new businesses or the elimination of existing ones.

The proposed code changes would apply to all businesses operating in California, regardless of whether the business is incorporated inside or outside of the state.[4] Therefore, the Statewide CASE Team does not anticipate that the proposed changes would have an advantageous or an adverse effect on the competitiveness of California businesses.

The Statewide CASE Team derived a reasonable estimate of the change in investment by California businesses based on the estimated change in economic activity

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[4] Gov. Code, §§ 11346.3(c)(1)(C), 11346.3(a)(2); 1 CCR § 2003(a)(3) Competitive advantages or disadvantages for California businesses currently doing business in the state.

associated with the proposed measure and its expected effect on business income. The Statewide CASE Team's IMPLAN modeling estimated a $248,530 increase in California business income due to the proposed code change. The Statewide CASE Team assumed that net business investment is positively correlated with business income and that a portion of business income will be allocated to net business.[5]

To estimate the portion of business income that would be allocated to net investment, the Statewide CASE Team analyzed national data on corporate profits and net capital investment by businesses that expand a firm's capital stock (referred to as net private domestic investment, or NPDI).[6] As Table 11 shows, between 2020 and 2024, NPDI as a percentage of corporate profits ranged from a low of 18 percent in 2020 due to the worldwide economic slowdowns associated with the COVID-19 pandemic, to a high of 28 percent in 2022, with an average of 23 percent. While only an approximation of the proportion of business income used for net capital investment, it provides a reasonable estimate of the proportion of proprietor income that business owners would reinvest into expanding their capital stock.

Table 11: Net Private Domestic Investment and Corporate Profits, U.S.

Year	Net Domestic Private Investment by Businesses, Billions of Dollars	Corporate Profits After Taxes, Billions of Dollars	Ratio of Net Private Investment to Corporate Profits (Percent)
2020	$389	$2,212	18%
2021	$545	$2,888	19%
2022	$825	$2,951	28%
2023	$836	$3,069	27%
2024	$885	$3,441	26%
5-Year Average	**-**	**-**	**23%**

Source: (Federal Reserve Economic Data (FRED) n.d.)

Given the estimated total increase in California business income and net business investment ratio described above, the Statewide CASE Team estimates the proposed code change would result in a $58,340 increase in net private investment by California businesses.

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[5] 23 percent of proprietor income was assumed to be allocated to net business investment; see Table 11.

[6] Net private domestic investment is the total amount of investment in capital by the business sector that is used to expand the capital stock, rather than maintain or replace due to depreciation. Corporate profit is the money left after a corporation pays its expenses.

2.3.5 Economic and Fiscal Impacts

The Statewide CASE Team does not anticipate that the economic impacts associated with the proposed measure would lead to a significant change (increase or decrease) in investment, directly or indirectly, in any affected sectors of California's economy. The proposed change would not result in economic disruption to any sector of the California economy. For more information on the Statewide CASE Team's economic and fiscal impacts methodology, see the 2028 CASE Methodology Report.

Adoption of this code change proposal would result in relatively modest economic impacts through additional direct spending by or on industrial contractors, energy consultants, and building inspectors. The Statewide CASE Team does not anticipate that money saved by businesses or other organizations affected by the proposed 2028 code cycle regulations would result in additional spending by those businesses.

2.3.5.1 Effects on the State General Fund, State Special Funds, and Local Governments

The Statewide CASE Team does not expect the proposed code changes to have a measurable impact on California's General Fund, any state special funds, or local government funds.

Cost to State: The state government already has a budget for code development, education, and compliance enforcement. While the state government would be allocating resources to update the Title 24, Part 6 Standards, including updating education and compliance materials and responding to questions about the revised requirements, these activities are already covered by existing state budgets. The costs for the state government are small when compared to the overall cost savings and policy benefits associated with the code change proposals. State buildings do not typically operate process boilers of qualifying size and so would not be directly impacted by this proposed measure.

Cost to Local Governments: All proposed code changes to Title 24, Part 6 would result in changes to compliance determinations. Local governments would need to train building department staff on the revised Title 24, Part 6 Standards. While this retraining is an expense to local governments, it is not a new cost associated with the 2028 code change cycle. The building code is updated on a triennial basis, and local governments plan and budget for retraining every time the code is updated. There are numerous resources available to local governments to support compliance training that can help mitigate the cost of retraining, including tools, training, and resources provided by the IOU Codes and Standards program (such as Energy Code Ace). As noted in Section 3, the Statewide CASE Team considered how the proposed code change might impact various market actors involved in the compliance and enforcement process and aimed to minimize negative impacts on local governments.

2.3.5.2 Mandates on Local Agencies or School Districts

There are no relevant mandates to local agencies or school districts because local agencies and schools do not typically operate process boilers of qualifying size.

2.3.5.3 Costs to Local Agencies or School Districts

There are no costs to local agencies or school districts because local agencies and schools do not typically operate process boilers of qualifying size.

2.3.5.4 Costs or Savings to Any State Agency

There are no costs or savings to any state agencies because these agencies do not typically operate process boilers of qualifying size.

2.3.5.5 Other Non-Discretionary Cost or Savings Imposed on Local Agencies

There are no added non-discretionary costs or savings to local agencies because local agencies do not typically operate process boilers of qualifying size.

2.3.5.6 Costs or Savings in Federal Funding to the State

The Statewide CASE Team did not identify any costs or savings to federal funding provided to the state.

2.4 Flash Steam Recovery – Cost Effectiveness

2.4.1 Cost Effectiveness Methodology

The Statewide CASE Team collaborated with CEC staff to confirm that the cost-effectiveness methodology aligns with CEC guidelines, including cost inclusion parameters. The 2028 CASE Methodology Report and Appendix A provide reproducibility details.

Per California Law (Public Resources Code 25000), a measure is considered cost effective if its Benefit-to-Cost Ratio (BCR) is 1.0 or greater, amortized over the economic life of the structure. The Statewide CASE Team calculates BCR by dividing total dollar benefits by total dollar costs over a 30-year analysis period.

Benefits are based on Long-term System Cost (LSC), which assigns an hourly dollar value to energy use. LSC hourly factors weigh the long-term value of each hour differently, where times of peak demand are valued more than off-peak hours. These factors are not utility rates, forecasts, or bill estimates. The CEC develops and publishes LSC hourly conversion factors for each code cycle. Costs include first costs and ongoing maintenance costs assessed over the 30-year period. Benefits and costs are evaluated incrementally, relative to the most recently adopted Energy Code.

2.4.2 Energy and Energy Cost Savings Results

To analyze the energy savings for the proposed flash steam recovery requirement, the Statewide CASE Team calculated the difference in energy consumption between the baseline (no flash steam recovery) and measure case (recovers all flash steam from boiler blowdown and routes it to the deaerator supply line).

The savings calculations used a custom analysis model. At a high level, the calculation steps were as follows:

1. **Baseline**: Model all mass and energy flows for a baseline boiler system, where all blowdown is lowered to atmospheric pressure and all flash steam is vented.
2. **Proposed**: Model all mass and energy flows for a measure case boiler system, where flash steam is recovered from boiler blowdown and routed to the deaerator.
3. **Savings**: The energy and water savings are taken as the differences in energy and water use between the baseline and proposed scenarios.

The total natural gas and water savings increase with the associated steam boiler's input capacity because the total volume of flash steam is higher at boilers with larger loads. To ensure cost-effectiveness, the proposed flash steam recovery requirement only applies to process boilers with an input rating (capacity) of 10 MMBtu/h or greater.

The more the boiler is operated, the greater the resultant savings. Boilers that operate infrequently throughout the year due to seasonal loads will therefore experience lower energy and water savings. Due to this variance, the Statewide CASE Team calculated annual energy savings and cost-effectiveness for boilers with seasonal loads separately from boilers with more typical annual loads. Calculations for boilers operating annually assumed 6,500 operating hours per year at 40 percent load, while calculations for seasonal boilers assumed 2,400 operating hours per year (primarily July through October) at 80 percent load. The Statewide CASE Team based these assumptions for operating hours and load factor on an analysis of data from a survey of 128 California steam-using sites in an Industrial Assessment Center (IAC) database. Savings from flash steam recovery should stay constant over the measured lifetime. However, components of the flash steam recovery system could fail, reducing the energy savings from the measure.

Per-unit savings for the first year are expected to be 30,900 kBtu per MMBtu/h of boiler capacity for year-round boilers and 22,800 kBtu per MMBtu/h of boiler capacity for seasonally operated boilers, as shown in Table 12. The energy and water savings scale linearly with boiler capacity, so the per-unit savings are the same for all boiler capacities. No electric savings or demand reductions are associated with this measure. The per-unit energy savings of this measure are not impacted by climate zone and are the same across new construction, additions, or alterations.

While energy savings do not differ across climate zones, the LSC factors do vary slightly by climate zone. Table 13 presents total per-unit energy cost savings for newly added boilers, expressed as LSC savings realized over a 30-year period, in 2029 present value dollars (2029 PV$) for year-round and seasonal boilers by climate zone.

Table 12: First Year Natural Gas Savings (kBtu) Per MMBtu/h of Boiler Capacity – Flash Steam

Boiler Category (All Boiler Capacities)	First Year Natural Gas Savings (kBtu)
Year-Round	30,900
Seasonal	22,800

Table 13: Savings (2029 PV$) Per MMBtu/h of Boiler Capacity – Flash Steam

Climate Zone	Year-Round Boilers	Seasonal Boilers
CZ 1	25,590	16,763
CZ 2	25,590	16,763
CZ 3	25,590	16,763
CZ 4	25,590	16,763
CZ 5	25,590	16,763
CZ 6	25,898	16,787
CZ 7	25,822	16,783
CZ 8	25,898	16,787
CZ 9	25,898	16,787
CZ 10	25,898	16,787
CZ 11	25,590	16,763
CZ 12	25,590	16,763
CZ 13	25,590	16,763
CZ 14	25,898	16,787
CZ 15	25,898	16,787
CZ 16	25,898	16,787

2.4.3 Incremental First Cost

The baseline case to estimate the costs of this measure is a process boiler system with no flash steam recovery. This baseline ensures cost effectiveness in the rare occasion that sites would need to replace existing flash steam recovery equipment to comply with this measure, in addition to sites without any flash steam recovery equipment. The incremental first costs are consistent between new boilers at new steam loads (new construction and additions) and newly installed replacement boilers at existing industrial facilities (alterations).

The incremental first cost of a blowdown flash steam recovery system includes the design, equipment, installation, startup, and commissioning costs of a pressurized flash steam recovery vessel, piping, isolation valves, and a check valve. The majority of the measure first cost comes from installation labor costs, followed by the material costs of piping, pipe insulation, and flash vessels. The cost of additional piping components and design, startup, and commissioning make up the remaining small proportion of the total first costs.

The flash vessel and flash steam piping are sized based on the estimated design condition blowdown mass flow. The pipe insulation is sized based on the pipe diameter and flash steam temperature in accordance with existing Title 24 requirements. To calculate costs, the Statewide CASE Team sized the flash vessel according to the vessel ratings of a major steam equipment vendor, which considers the total blowdown mass flow—liquid and flash steam. The Statewide CASE Team sized the pipe diameter to maintain flash steam velocity under 3,000 feet per minute and rounded the output to the next highest nominal pipe diameter, which is a conservative industry rule of thumb.

The Statewide CASE Team obtained flash vessel costs from a manufacturer in October 2024 and scaled the costs by steam load to estimate the flash vessel costs for each boiler capacity. The Statewide CASE Team confirmed the base costs in May 2026 through vendor websites. To estimate piping and piping insulation costs, the Statewide CASE Team used information from the software platform RSMeans in September and October 2025. The Statewide CASE Team estimated the ancillary materials costs (valves, strainers, and fittings) and labor costs required to design a flash steam recovery system and the costs of commissioning and compliance verification based on field experience and historical project costs.

Table 14 shows the total estimated incremental first costs of installing a flash steam recovery system by boiler capacity. A breakdown of the cost calculations and sources for a boiler with an input capacity of 32.6 MMBtu/h is included in Table 47 in Appendix A. When sized for larger steam loads, piping and associated components are larger and more expensive. The incremental first costs for seasonal boilers and boilers that operate year-round are equivalent because the systems are typically sized for similar load factors regardless of the actual operating load factors. The Statewide CASE Team calculated the first costs for all systems, assuming they were sized for boilers operating at 80 percent load. For some specific flash steam recovery applications, a site may install additional equipment. All incremental first costs are expected to increase with inflation.

When calculating measure costs and savings, the Statewide CASE Team used the average boiler capacity among boilers in each boiler capacity range to represent all boilers in that size range. The midpoints and ranges are provided in Table 46. The Statewide CASE Team assumed a conservative piping distance of 100 feet between the flash recovery at boiler blowdown and the deaerator to calculate measure energy savings across both seasonal and year-round boilers.

Table 14: Flash Steam Recovery System Incremental First Cost by Boiler Capacity

Boiler Capacity	Flash Steam Recovery System First Cost	Flash Steam Recovery System First Cost Per MMBtu/h of Capacity
10-15[7] MMBtu/h	$18,900	$1,579
15-25 MMBtu/h	$18,900	$972
25-50 MMBtu/h	$22,970	$705
50-100 MMBtu/h	$25,716	$364
100-200 MMBtu/h	$30,854	$216
200+ MMBtu/h	$72,381	$98

Depending on a site's steam distribution system, flash steam recovery equipment installation at an existing site could marginally lengthen the downtime of existing steam loads during the connection of the new boiler to the existing system. In most cases, the Statewide CASE Team expects the site to connect the new flash steam recovery system at the same time as the new steam boiler, and any incremental downtime due to the flash steam recovery system would be insignificant compared to the necessary downtime to install the replacement boiler. Most year-round facilities plan for one to two weeks of downtime annually or semi-annually and would typically connect the new boiler and new flash steam recovery equipment during this planned downtime.

2.4.4 Incremental Maintenance and Replacement Costs

The incremental maintenance cost for a flash steam recovery system includes the cost of replacing pipe insulation. Maintenance for the flash vessel and the piping itself were not included in the cost estimates, as the lifespans of stainless steel and carbon steel vessels and piping range from 20 to 50 years or more (Pak Industrial Services, n.d.). A detailed breakdown of incremental maintenance and replacement costs is provided in Table 48.

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[7] All boiler capacity bins use an inclusive lower bound. For example, the 10-15 MMBtu/h bin means 10 ≤ boiler capacity < 15.

Insulating steam piping can reduce energy loss to the atmosphere by up to 90 percent, making piping insulation maintenance crucial to conserving energy and reducing heat loss over time (DOE, 2012). DOE estimates that heat is lost at a rate of 285 MMBtu per year per 100-foot stretch of 1-inch uninsulated pipe on a 150 psig system—equivalent to $2,565 of natural gas costs per year at an average price of $0.90/therm (DOE, 2012). Insulation damage usually results from selecting the wrong type or quantity of insulation for the process, improper installation practices, physical damage (such as walking or climbing on uninsulated pipes), or corrosion or contamination caused by exposure to process or steam leaks (Multiservice Industrial, 2022). Maintenance and replacement of damaged piping insulation can be performed by general maintenance staff and are important to ensure the measure savings persist throughout the 30-year analysis period.

The incremental cost of insulation maintenance is based on an assumed insulation degradation rate of one percent per year. The Statewide CASE Team assumed that insulation maintenance occurs every 10 years, with costs estimated as a proportional share of the original installation cost based on the amount of insulation replaced. The Statewide CASE Team based the maintenance and replacement frequency estimates on the 2025 Process Pipe Load CASE Report (Amoni & Alkhatib, 2023).

For detailed maintenance cost information, see Appendix A. Descriptions of the estimation of present value of maintenance and replacement costs are provided in the 2028 CASE Methodology Report.

2.4.5 Cost Effectiveness

The Statewide CASE Team evaluated per-unit cost-effectiveness for both year-round operation and seasonal boilers at six boiler capacities to ensure cost-effectiveness of the proposed requirement for boilers with lower annual operating hours and across the size range covered by the proposed measure.

Results of the per-unit cost-effectiveness analyses are presented in Table 15 and Table 16. The proposed measure saves money over the 30-year period of analysis relative to the existing conditions. The proposed measure is cost effective in every climate zone and for alterations (newly installed boilers at existing sites) in addition to additions and new construction. The results do not vary between new construction, additions, and alterations.

In Table 15 and Table 16, all values are presented in 2029 present value dollars (PV$). Benefits represent 30-year LSC savings and other savings, including incremental first-cost savings if the proposed first cost is less than the current first cost, incremental maintenance cost savings if the proposed maintenance costs are less than the current maintenance costs, and incremental residual value if proposed residual value is greater than current residual value at the end of the 30-year period of analysis. Costs represent the total incremental PV cost, including incremental equipment, replacement, and maintenance costs over the period of analysis. The analysis treats a negative incremental maintenance cost as a positive benefit. If total incremental costs are zero, the BCR is considered infinite. Costs and other savings are discounted at a real (inflation-adjusted) three percent rate. If there are no total incremental PV costs, the BCR is infinite. A BCR of “NA” indicates that there is no boiler capacity in that climate zone that would be impacted by the proposed requirement. As the changes in LSC savings only vary very slightly by climate zone, Table 15 includes the LSC savings for Climate Zone 1.

The BCR values indicate that flash steam recovery systems are highly cost-effective investments with strong society-level benefits. However, the LSC metric is a system-level valuation metric rather than a prediction of customer utility bills or customer-specific benefits. Industrial decision-makers are likely to evaluate investment decisions using their anticipated facility energy rates, operational considerations, maintenance impacts, and internal capital criteria. Industrial energy costs for individual facilities may be materially different depending on negotiated service agreements.

Based on simple payback calculations with market energy prices for industrial customers[8], the expected payback periods based on energy savings range from under one year to over five years, depending on boiler capacity and frequency of operation. While the return on investment is clear, industrial facility owners often prefer to minimize immediate capital expenses and operate with a high barrier for capital expenditure on auxiliary equipment (Energy Efficiency Movement, 2025). Typical investments for industrial process equipment have payback periods of one to three years.

While the cost-effectiveness is apparent when evaluating the costs and benefits of flash steam recovery, many facility owners do not consider flash steam recovery when designing boiler systems because venting flash steam is industry standard practice.

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[8] Simple payback calculations used natural gas prices of $1.30/therm, based on data from EIA and confirmed by IAC data from industrial sites in California from 2024 and 2025 (DOE 2026, EIA 2026).

Table 15: 30-Year Cost-Effectiveness Summary Per MMBtu/h of Boiler Capacity – Flash Steam

Boiler Category	Benefits LSC Savings + Other PV Savings (2029 PV$)	Costs Total Incremental PV Costs (2029 PV$)	Benefit-to-Cost Ratio
Year-Round Boiler 10-15 MMBtu/h	$25,746.06	$2,070.85	12.43
Year-Round Boiler 15-25 MMBtu/h	$25,743.87	$1,274.38	20.20
Year-Round Boiler 25-50 MMBtu/h	$25,720.50	$911.45	28.22
Year-Round Boiler 50-100 MMBtu/h	$25,608.14	$466.52	54.89
Year-Round Boiler 100-200 MMBtu/h	$25,664.62	$273.10	93.97
Year-Round Boiler 200+ MMBtu/h	$25,804.58	$116.17	222.13
Seasonal Boiler 10-15 MMBtu/h	$16,775.30	$2,070.85	8.10
Seasonal Boiler 15-25 MMBtu/h	$16,775.10	$1,274.38	13.16
Seasonal Boiler 25-50 MMBtu/h	$16,773.34	$911.45	18.40
Seasonal Boiler 50-100 MMBtu/h	$16,764.83	$466.52	35.94
Seasonal Boiler 100-200 MMBtu/h	$16,769.08	$273.10	61.40
Seasonal Boiler 200+ MMBtu/h	$16,779.64	$116.17	144.44

Table 16: Benefit-to-Cost Ratio – Flash Steam

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round 10-15 MMBtu/h	12.4	12.4	12.4	12.4	12.4	12.5	12.5	12.5	12.5	12.5	12.4	12.4	12.4	12.5	12.5	12.5
Year-Round 15-25 MMBtu/h	N/A	20.1	20.1	20.1	20.1	20.3	20.3	20.3	20.3	20.3	20.1	20.1	20.1	20.3	20.3	20.3
Year-Round 25-50 MMBtu/h	28.1	28.1	28.1	28.1	28.1	28.4	28.3	28.4	28.4	28.4	28.1	28.1	28.1	28.4	28.4	28.4
Year-Round 50-100 MMBtu/h	N/A	54.9	54.9	54.9	54.9	55.5	55.4	55.5	55.5	55.5	54.9	54.9	54.9	55.5	55.5	55.5
Year-Round 100-200 MMBtu/h	N/A	93.7	93.7	93.7	N/A	94.8	N/A	94.8	94.8	94.8	93.7	93.7	93.7	94.8	94.8	94.8
Year-Round 200+ MMBtu/h	220.3	220.3	220.3	220.3	N/A	222.9	N/A	222.9	222.9	222.9	220.3	220.3	220.3	222.9	222.9	222.9
Seasonal 10-15 MMBtu/h	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Seasonal 15-25 MMBtu/h	N/A	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Seasonal 25-50 MMBtu/h	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Seasonal 50-100 MMBtu/h	N/A	35.9	35.9	35.9	35.9	36.0	36.0	36.0	36.0	36.0	35.9	35.9	35.9	36.0	36.0	36.0
Seasonal 100-200 MMBtu/h	N/A	61.4	61.4	61.4	N/A	61.5	N/A	61.5	61.5	61.5	61.4	61.4	61.4	61.5	61.5	61.5
Seasonal 200+ MMBtu/h	144.3	144.3	144.3	144.3	N/A	144.5	N/A	144.5	144.5	144.5	144.3	144.3	144.3	144.5	144.5	144.5

2.5 Flash Steam Recovery – Statewide Impacts

2.5.1 Statewide Energy and Energy Cost Savings

The Statewide CASE Team took the following steps to determine statewide savings from the proposed flash steam recovery measure.

First, the Statewide CASE Team used a statewide boiler inventory of local AQMD boiler permits (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025) to estimate statewide boiler capacities by boiler capacity bins. More information on the data can be found in Appendix C.

The Statewide CASE Team refined the statewide capacity for each capacity bin to account for Title 24, Part 6 purview and to measure qualification, initially making the following changes:

1. Removed boilers with input capacities under 10 MMBtu/h and any units that were indicated to be hot water boilers or hot water heaters in the permit data.
2. Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements.
3. Removed five percent of remaining boiler capacity to account for boilers that are not served by a pressurized deaerator and boilers that are expected to qualify for the measure exceptions, based on field experience.
4. Assumed the cannery industry used seasonal boilers and thus separated them from year-round boilers.
    - The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processors in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes represents the Existing Steam Boiler Stock. Boilers in the healthcare, education, lumber, and refinery sectors were included in the statewide capacity totals.

To estimate the capacity of new process boilers installed annually from new construction and additions, the Statewide CASE Team calculated two Industrial Product Growth Rates (IPGRs) for California process boiler capacity, one for year-round boilers and one for seasonal boilers. See Appendix C for details on how the Statewide CASE Team calculated the IPGRs. The annual new construction and additions forecast is equivalent to the Existing Boiler Stock multiplied by the IPGR.

To estimate the capacity of new process boilers installed annually from alterations or replacements, the Statewide CASE Team calculated the replacement rate for boilers and applied it to Existing Boilers Stock. Boiler lifetimes range widely, with most estimates in the 25- to 40- year range (Van Wortswinkel & Nijs, 2010). The boiler replacement rate is based on a 30-year boiler lifetime, which means that 3.3 percent of the Existing Boiler Stock is replaced each year. The annual boiler alterations forecast is therefore equivalent to the Existing Boiler Stock multiplied by 3.3 percent.

The Statewide CASE Team then multiplied the per-unit measure savings by the annual new construction and additions forecast and by the alterations forecast to obtain first-year statewide savings before accounting for natural market adoption.

To estimate the share of new qualifying boilers that would install blowdown flash steam recovery systems without the requirement in place, the Statewide CASE Team leaned on input from boiler manufacturers and vendors during stakeholder interviews and an analysis of IAC Audit Data from 64 boilers at 32 steam-using industrial plants from 2010 to 2022. To account for natural market adoption and arrive at the final statewide savings estimate, the Statewide CASE Team removed 10 percent of boiler capacity across capacity bins from the statewide savings.

More details on the methodology and context about estimating the statewide energy and energy cost savings can be found in the 2028 CASE Methodology Report. Appendix C presents the assumptions on the percentage of the total statewide process boiler capacity that the proposed measure would impact.

The tables below present the first-year statewide energy and LSC savings from newly constructed buildings and additions (Table 17) and alterations (Table 18) by climate zone. Table 19 presents first-year statewide savings from new construction, additions, and alterations.

Table 17: Statewide Energy and LSC Impacts – New Construction and Additions

Climate Zone	Statewide New Construction and Additions Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	5.33	-	-	0.00	0.14	$0.13
2	12.99	-	-	0.00	0.34	$0.33
3	86.71	-	-	0.03	2.28	$2.19
4	35.08	-	-	0.01	0.92	$0.88
5	7.10	-	-	0.00	0.19	$0.18
6	58.48	-	-	0.02	1.53	$1.49
7	16.01	-	-	0.00	0.42	$0.41
8	89.83	-	-	0.03	2.34	$2.29
9	110.53	-	-	0.03	2.88	$2.82
10	74.57	-	-	0.02	1.95	$1.90
11	39.86	-	-	0.01	1.04	$0.99
12	259.94	-	-	0.08	6.85	$6.58
13	289.89	-	-	0.09	7.65	$7.35
14	39.28	-	-	0.01	1.02	$0.99
15	19.82	-	-	0.01	0.52	$0.50
16	10.54	-	-	0.00	0.27	$0.27
Total	**1,155.96**	**-**	**-**	**0.35**	**30.34**	**$29.31**

Table 18: Statewide Energy and LSC Impacts – Alterations

Climate Zone	Statewide Alterations Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	12.73	-	-	0.00	0.32	$0.30
2	29.25	-	-	0.01	0.75	$0.71
3	192.14	-	-	0.06	4.94	$4.70
4	78.72	-	-	0.02	2.01	$1.92
5	14.51	-	-	0.00	0.38	$0.37
6	130.26	-	-	0.04	3.32	$3.22
7	32.66	-	-	0.01	0.86	$0.84
8	203.95	-	-	0.06	5.17	$4.99
9	249.66	-	-	0.07	6.34	$6.13
10	167.63	-	-	0.05	4.26	$4.12
11	95.28	-	-	0.03	2.39	$2.26
12	567.91	-	-	0.17	14.67	$13.99
13	624.12	-	-	0.19	16.20	$15.48
14	92.00	-	-	0.03	2.31	$2.22
15	45.68	-	-	0.01	1.15	$1.11
16	24.27	-	-	0.01	0.61	$0.59
Total	**2,560.75**	**-**	**-**	**0.77**	**65.67**	**$62.95**

Table 19: Statewide Energy and LSC Impacts – New Construction, Additions, and Alterations

Construction Type	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction (MW)	First -Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
New Construction and Additions	-	-	0.35	30.34	$29.31
Alterations	-	-	0.77	65.67	$62.95
Total	**-**	**-**	**1.12**	**96.01**	**$92.27**

2.5.2 Statewide Greenhouse Gas Emissions Reductions

Table 20 presents the estimated first-year avoided GHG emissions resulting from the proposed code change. In this initial year, the Statewide CASE Team expects the proposed measure to avoid 5,840 metric tons of carbon dioxide equivalent (CO_2e) emissions. These reductions, along with their associated monetary value, were calculated using hourly GHG emissions factors published alongside the LSC hourly factors and source energy hourly factors in the research versions of CBECC, as well as data from the CEC's 2028 Metrics Report. See the 2028 CASE Methodology Report for additional information.

Table 20: First-Year Statewide GHG Emissions Impacts

Construction Type	Avoided GHG Emissions from Electricity Savings (Metric Tons CO_2e)	Avoided GHG Emissions from Natural Gas Savings (Metric Tons CO_2e)	Total Avoided GHG Emissions (Metric Ton CO_2e)	Total Monetary Value of Avoided GHG Emissions ($)
New Construction	0	0	1,845.56	$299,828.96
Additions & Alterations	0	0	3,994.43	$648,934.46
Total	**0**	**0**	**5,839.98**	**$948,763.42**

2.5.3 Statewide Water Use Impacts

The water savings are equivalent to the difference in baseline and proposed flash steam mass flows. Appendix A contains further calculation details.

Table 21 presents the per-unit and statewide impacts on water use. In the initial year of the requirement, the Statewide CASE Team expects the proposed measure to avoid over 11 million gallons of water use. See the 2028 CASE Methodology Report for additional information on the embedded electricity savings estimates, which assume embedded energy factors of 5,440 kWh per million gallons of water for indoor use and 3,280 kWh per million gallons of water for outdoor water use (SBW Consulting, Inc. 2022).

Table 21: Impacts on Water Use and Embedded Electricity in Water

Impact	On-Site Indoor Water Savings (Gallons/Year)	On-site Outdoor Water Savings (Gallons/Year)	Embedded Electricity Savings (kWh/Year)
Average Per Unit (MMBtu/h) Impacts	2,974	-	16
First-Year Statewide Impacts for New Construction	3,492,673	-	19,000
First-Year Statewide Impacts for Additions and Alterations	7,559,595	-	41,124
Total First-Year Statewide Impacts	**11,052,267**	**-**	**60,124**

2.5.4 Statewide Material Impacts

The proposed code change requires the installation of flash steam piping and vessels. However, even without a flash steam recovery system, existing sites would already have, or new sites would install, an atmospheric flash tank. The atmospheric tank would be replaced by the pressurized flash steam recovery vessel in most cases, and installation of the flash steam recovery vessel would not lead to a net increase in material use. Flash steam piping is typically made of carbon steel and stainless steel (Ryan Waldron, 2023). The proposed requirement would lead to an increase in the demand for steel at industrial sites as shown in Table 22. For more information on the Statewide CASE Team's methodology and assumptions used to calculate embodied GHG emissions, see the 2028 CASE Methodology Report.

Table 22: First-Year Statewide Impacts on Material Use

Material	Impact	Per-Unit Impacts (Pounds per MMBtu/h)	First-Year Statewide Impacts (Pounds)	Embodied GHG emissions saved (Metric Tons CO_2e)
Mercury	No change	-	-	-
Lead	No change	-	-	-
Copper	No change	-	-	-
Steel	Increase	0.42	1,568	-1
Plastic	No change	-	-	-
TOTAL	**N/A**	**0.42**	**1,568**	**-1**

2.5.5 Environmental Impacts

The Statewide CASE Team considered opportunities to minimize the environmental impact of the proposal, including evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide

CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

The proposed measure would reduce water use, energy consumption, and ozone production. Flash steam recovery systems reduce system water use by using recovered flash steam to serve low-pressure loads instead of down-regulating live boiler steam. Fresh make-up water also requires additional heating from the boiler, so replacing it with recovered flash steam reduces boiler fuel consumption. The reduction in energy consumption because decreased combustion would also improve local air quality and reduce ozone and local photochemical smog, as the combustion of natural gas produces nitrogen oxides (NOx), which are precursors to ozone (Chen, Omotesho, & Johnson, 2025).

2.5.6 Other Non-Energy Impacts

In addition to reducing water use, flash steam recovery reduces the use of chemicals used to treat incoming boiler feedwater.

2.6 Flash Steam Recovery – Proposed Code Language

2.6.1 Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes follow the restructured 2025 Building Energy Efficiency Standards and are marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

New to the 2028 energy code is to *italicize defined terms* when the terms are being used in its defined context. In-line comments that are not part of the proposed code language but are used to help describe the purpose of what is proposed are included *with greyed highlight and italics.*

Markups are provided to the restructured 2025 Energy Code that the CEC developed in response to feedback that aligning the structure of Title 24, Part 6 with other parts of the California Building Standards Code (Title 24) would improve readability, usability, and navigation.[8] New section numbers are shown as bold followed square brackets that document the section in the 2025 Title 24, Part 6 section numbers prior to the restructuring. For example, "**Section 601.1** [Section 130.0(a)] **General"** contains the content that is in the current Section 130.0(a).

Posting the proposed code language in this format is useful as it helps describe how the Energy Code changes proposed for nonresidential occupancies are isolated from the requirements for residential occupancies which are prohibited from being changed until the 2031 code cycle by Assembly Bill 130.

2.6.2 Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

2.6.3 Energy Code (Title 24, Part 6)

SECTION 200 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 201 [Section 100.1(b)] **– Definitions – Recommends new or revised definitions for the following terms:**

FLASH STEAM is water vapor that is generated when condensate is dropped to a pressure lower than its saturation pressure, which then vaporizes a fraction of the liquid in a process called flashing.

PRESSURIZED CONDENSATE RETURN is a steam condensate return system that continuously operates at a pressure above 15 psig during normal operation and is not vented to atmosphere. The system contains liquid condensate and any associated steam vapor that may be present in the piping.

SUBCHAPTER 9 – PROCESS SYSTEMS AND EQUIPMENT

SECTION 904 – PROCESS BOILERS (NEWLY CONSTRUCTED, ADDITIONS, ALTERATIONS)

904.1 [Section 120.6(d)] **Mandatory requirements (Newly Constructed, Additions, Alterations).**

904.1.4 *[New section]* **Flash steam recovery.**

All newly installed process steam boilers with capacities at or above 10 MMBtu/h that have or are connected to a system with a pressurized deaerator shall recover and route *flash steam* from blowdown to the deaerator or another heating load.

> **Exception 1 to 904.1.4**: Process steam boiler systems where high-pressure condensate is returned to the deaerator without being flashed (dropped to atmospheric pressure).
>
> **Exception 2 to 904.1.4**: Process steam boiler systems where the linear distance (sum of horizontal and vertical) from the boiler to the serving deaerator is greater than or equal to 100 feet.
>
> **Exception 3 to 904.1.4:** Process steam boilers in hotel/motel buildings and nonresidential buildings with Group R occupancies.

904.4 [Section 141.1] **Additions and alterations to existing buildings.**

Covered processes in additions or alterations to existing buildings that will be nonresidential, hotel/motel, or multifamily occupancies shall comply with the applicable requirements of Section 904, and the applicable requirements of Section 400.5.1 [Section 110.2(a)] and Section 913 [Section 120.3].

> All additions or alterations to existing buildings where process steam boilers are added or replaced shall comply with the applicable requirements of Section 904.1.

2.6.4 Reference Appendices

No changes are proposed to the Reference Appendices.

2.6.5 Compliance Manuals

The Statewide CASE Team will provide the CEC with recommended revisions to compliance manuals after the 45-Day Language is published.

2.6.6 ACM Reference Manual

No changes are proposed to the ACM Reference Manual.

2.6.7 Compliance Forms

As discussed in Section 2.1.4.5, NRCC-PRC-E and NRCI-PRC-E compliance forms would be updated or added to reflect the proposed change. The Statewide CASE Team can support the CEC in implementing these updates if the proposed change is adopted. These potential updates would look as follows:

NRCC-PRC-E

Within section I PROCESS BOILER table:

- Create the following columns in the table:
  - Which rated input capacity aligns with this process steam boiler system (Btu/h)?
    - In the Virtual Compliance Assistant, add the following dropdown options:
      - Rated input capacity for one or more connected boilers: ≥ 5 to < 10 MMBtu/h
      - Rated input capacity for one or more connected boilers: ≥ 10 MMBtu/h
  - Does the process steam boiler recover and route flash steam from boiler blowdown to the deaerator or another heating load?
    - In the Virtual Compliance Assistant, add the following dropdown options:

        - Yes
        - This doesn't apply because the process boiler has a rated capacity less than 10 MMBtu/h.
        - This doesn’t apply because the system will not have a pressurized deaerator.
        - This doesn’t apply because the system will install a pressurized condensate return system.
        - This doesn’t apply because the linear distance from the boiler to the serving deaerator is greater than or equal to 100 feet.

NRCI-PRC-E

- Add the following to the Process Boilers Table:
    - Column for Blowdown Flash Steam Recovery compliance. (P/F)
        - Verify that the flash steam recovery vessel is installed with overhead piping connected to a deaerator or another approved end use. (P/F)
        - Verify that all valves on the flash steam recovery vessel overhead piping between the vessel and the point of use are installed and in the open position. (P/F)

3. Condensate Return

3.1 Condensate Return – Measure Description

3.1.1 Proposed Code Change

A process steam system is a system that uses one or more steam boilers to serve loads other than space heating or service water heating for human occupants, such as manufacturing or industrial processes. As process loads use steam, the steam condenses into hot liquid condensate. A condensate return system, consisting of piping, collection tanks, and pumps, returns hot condensate to the boiler system for reuse.

This proposed measure would require newly constructed process steam loads that use indirect-contact heat exchangers to return all steam condensate to the boiler for reuse via a condensate return system.

The proposed requirement would only apply to steam loads that meet certain criteria for load size and condensate return piping lengths. Condensate return from direct steam injection (that comes in direct contact with the process) would be exempt from the requirement for condensate return.

To determine qualification for the requirement via load size and condensate return piping lengths, the linear distance (sum of horizontal and vertical) from the load to the condensate return tank or the deaerator must be under a specific maximum length depending on the steam flow of the load. Table 23 specifies the maximum linear distance for each steam flow range.

All steam loads with a linear distance above the maximum distance for the corresponding steam flow shall include the distance from the load to the condensate return tank or the deaerator in the steam system construction documents to prove that the requirement is not applicable to that steam load.

Table 23: Steam Load Condensate Return Distance Code Trigger Criteria

Steam Flow (lbs/h)	Linear Distance[9] (ft) less than
<1,000	Exempt
≥1,000, <2,000	400
≥2,000, <3,000	600
≥3,000, <4,000	800
≥4,000, <6,000	1,100
≥6,000	1,300

Table 24 summarizes the scope of the proposed code change.

Table 24: Scope of Proposed Code Change

A ☑ indicates the proposed code change is relevant.

Building Type(s)	Construction Type(s)	Type of Change
☐ Single Family	☑ New Construction	☑ Mandatory
☐ Multifamily	☑ Additions	☐ Prescriptive
☑ Nonresidential (not Group R uses)	☑ Alterations	☐ Performance

Application Climate Zones	Energy Code Sections	Compliance Forms	Sections of ACM Reference Manuals
Climate Zones 1-16	Part 6, Sections 100, 201 and 909.1	NRCC-PRC-E NRCI-PRC-E	N/A

Third Party Verification	Updates to Compliance Software
☑ No changes to third party verification	☑ No updates
☐ Update existing verification requirements	☐ Update existing feature
☐ Add new verification requirements	☐ Add new feature

3.1.2 Benefits of Proposed Change

Condensate return is a widely accepted best practice for steam systems and provides significant fuel and water savings by reducing the need for make-up water and the fuel used to pre-heat it. During the October 29 Utility-Sponsored Stakeholder Meeting covering this proposed measure, one stakeholder commented, “Given California's historic water shortage issues, how has [condensate return] not been incorporated in Title 24 [requirements] already?”

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[9] Linear distance (sum of horizontal and vertical) from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

Because condensate is effectively distilled water, its recovery also reduces the need for boiler blowdown, which results in additional energy savings. Depending on site conditions, condensate return is expected to yield energy savings of approximately 5 percent to 8 percent of baseline boiler system fuel use.

There are two main sources of energy and water savings when condensate is returned to the boiler for reuse: (1) the warmer returned condensate decreases the fuel required to preheat fresh make-up water for boiler feedwater, and (2) boiler feedwater from condensate return has fewer dissolved solids, reducing the need for blowdown and associated blowdown losses. As less fresh make-up water is needed, overall water use is reduced along with chemicals used for water treatment. Some sites may also benefit from a reduction in wastewater costs.

The reductions in fuel consumption, water, and chemicals for water treatment associated with condensate return all reduce costs for facilities. Overall, condensate return is highly cost-effective. During a stakeholder interview, one boiler manufacturer told the Statewide CASE Team that condensate return was one of the top three recommendations for site owners purely from an economic standpoint, saying, “Most people know that condensate is extremely lucrative to pump back.”

In addition to the energy and water benefits, these practices may reduce local photochemical smog and improve air quality. The value of improved air quality is amplified by the consideration that industrial facilities are disproportionately located near LMI housing. Ancillary benefits include improved public perception through reduction of steam plumes.

3.1.3 Background Information

In process steam systems, condensate forms when steam releases its heat of condensation in a heat exchanger, condensing into liquid. After process loads use steam, hot condensate remains and is collected in drip legs, which are vertical pipe sections designed to prevent the condensate from accumulating in the pipes. The condensate can be drained to wastewater or returned to the boiler for reuse. Condensate that is drained to waste must be replaced with fresh, cold make-up water, which requires chemical treatment and heating. When reused, condensate is ideal for boiler feedwater because it is essentially warm, distilled water and requires less heating or chemical treatment than fresh make-up water.

DOE literature has recommended increasing the percentage of returned condensate as a steam system best practice in since at least the early 2000s, and DOE provides a steam tip sheet specifically on improving condensate return (DOE, 2012). This proposed code change originated from discussions with California-based consulting engineers from strategic energy management programs and the DOE IAC program. The International Energy Conservation Code (IECC) does not cover condensate return and

ASHRAE does not have a specific standard for condensate return, but ASHRAE does outline considerations for condensate return in piping design, steam system operation, and energy efficiency.

Processes that use steam in direct contact with a product or contaminant per design or during normal operation are exempt from the proposed condensate return requirement because the steam, and therefore the condensate formed from the steam, may be contaminated with particulate matter and is not fit for immediate reuse.

To the knowledge of the Statewide CASE Team, condensate return requirements have not been proposed in previous code cycles. In 2013, Title 24 Part 6 first adopted requirements for process boilers. In 2022, Title 24 Part 6 adopted requirements for strainers and fault detection and diagnostics in steam trap assemblies.

3.1.4 Modifications to Energy Code Documents

This section provides descriptions of how the proposed code change will affect each Energy Code document. See Section 3.6.1 of this report for detailed revisions to code language.

3.1.4.1 Energy Code Change Summary

SECTION 200 – DEFINITIONS AND RULES OF CONSTRUCTION

Subsection 201: The proposed measure would add new definitions for a process steam system and condensate return system.

SECTION 909[10] – PROCESS STEAM SYSTEMS (NEW CONSTRUCTED, ADDITIONS, ALTERATIONS)

Subsection 909.1. Mandatory Requirements (Newly Constructed, Additions, Alterations).

Subsection 909.1.2: The proposed regulations would add a requirement for a condensate return system that returns condensate to the boiler plant for reuse at all newly constructed process steam loads. The requirement would only apply to steam systems that meet certain criteria for load size and condensate return piping lengths and would not include condensate return from direct steam injection.

3.1.4.2 Reference Appendices Change Summary

There are no proposed changes to the reference appendices.

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[10] The Statewide CASE Team proposes updating Subsection 909 from “STEAM TRAPS” to “PROCESS STEAM SYSTEMS” so that it may include all requirements for process steam systems.

3.1.4.3 Compliance Manuals Change Summary

The proposed changes would create a new section in the Nonresidential Compliance Manual, which would outline mandatory requirements for process steam systems. A newly created sub section would explain the condensate return requirement and verification steps.

3.1.4.4 Alternative Calculation Method Reference Manual Change Summary

The proposed measure will not modify ACM Reference Manuals because the proposed measure requires no associated software updates.

3.1.4.5 Compliance Forms Change Summary

The existing Process System Certificate of Compliance form (NRCC-PRC-E) would need to add a new section for process steam systems to document system qualification for the proposed condensate return requirement and whether the system includes a condensate return system that returns all condensate from indirect-contact heat exchangers and drip legs to the boiler for reuse. Where applicable, the form would also include documentation supporting the steam loads pipe length limitations, including reference to the relevant calculation. The Process System Certificate of Installation form (NRCI-PRC-E) would be updated to include a new table for process steam systems, including input fields to confirm that qualified systems meet the condensate return requirements as specified in the NRCC-PRC-E. Additional fields would document installation details of the condensate return system, including the presence of a condensate return system, associated pumps (if applicable), and labeled piping to verify proper system configuration and installation.

3.1.5 Measure Context

3.1.5.1 Comparable Model Codes or Standards

Review has found no relevant and comparable model codes or standards for context.

3.1.5.2 Interactions with Other Regulations

While ASHRAE does not have a specific standard for condensate return, it has considerations for condensate return in piping design, steam system operation, and energy efficiency. Review found no known existing federal, state, or local regulatory requirements that address condensate return in process steam systems. Current Title 24, Part 6 requirements cover steam traps in new industrial facilities and steam traps added to support new, non-replacement, process equipment in existing industrial facilities where the installed steam trap operating pressure is greater than 15 psig and the total combined connected boiler input rating is greater than 5 MMBtu/h. The code requires central steam trap fault detection and diagnostics monitoring, steam trap fault detection, and steam trap strainer installation. The proposed condensate return requirement discussed in this document would have no impact on these existing requirements. There are no known interactions with other parts of the California Building Code or local requirements. The proposed requirement would not interfere with compliance with OSHA requirements for pressurized vessels or AQMD requirements related to boiler emissions.

3.2 Condensate Return – Compliance and Enforcement

3.2.1 Compliance Considerations

When developing this proposal, the Statewide CASE Team considered methods to streamline the compliance and enforcement process and to mitigate or reduce negative impacts on market actors involved in the process. The Statewide CASE Team believes that compliance and enforcement of the proposed measure is feasible and would not add significant compliance and enforcement burdens to those responsible for ensuring compliance with the building code.

To ensure compliance with the proposed condensate return requirement, confirmation steps must be taken during the permit application (plan review), installation, and inspection by the Authority Having Jurisdiction (AHJ) or building department. New sections and input fields would need to be added to the Process Systems Certificate of Compliance Form NRCC-PRC-E and the Process System Certificate of Installation Form NRCI-PRC-E, and the forms completed.

Designers: Designers would need to be aware of the new condensate return requirement in Section 909.1, enabling design compliant process steam systems. They would need to fill out an updated NRCC-PRC-E form and to submit design documents indicating a compliant design. Plans must indicate planned installation of condensate return, including pipe length and pipe size (or else the planned installation of direct steam injection). If the steam load does not qualify for the requirement based on the code trigger table, they must include calculations documenting the linear distance from the steam trap serving the load to the condensate return tank or the deaerator in the steam system construction documents to prove that the requirement is not applicable to that steam load.

AHJ plan checkers: During the permit application phase, AHJ plan checkers would review the submitted NRCC-PRC-E form and design documents to confirm that the design includes either direct steam injection lines or condensate return piping for each load or does not qualify for the requirement because they exceed the maximum linear distance for the associated steam flow in the code trigger table.

Installation contractors: Installation contractors would be required to correctly install condensate return lines in accordance with design and manufacturing specifications, which their normal operating procedures already require. The installation contractors will document the installation in the NRCI-PRC-E form unless done by another party. When the installation contractor fills in the Certificate of Installation form, they would need to include confirmation of labeled condensate return piping.

Field technicians: Field technicians are typically the installers or technicians configuring the boiler system controls and are not certified Acceptance Testing Technicians (ATT). Field technicians may complete the condensate return fields in the process steam systems section of the NRCI-PRC-E form if the installation contractors do not complete them. Compliance verification includes confirmation of condensate return system installation. Sites seeking to reduce compliance burdens can have the commissioning technicians who tune the equipment prior to AQMD-required stack testing also confirm installation of the condensate return system. Field technicians may experience additional site maintenance visits if the condensate return pump fails.

AHJ building inspectors. In addition to the process boiler inspection items already required for a new boiler installation, the AHJ building inspector would need to verify the installation of condensate return system (tanks and piping) from all loads with heat exchangers.

Review finds that all definitions added for new proposed code language do not conflict with any existing definitions in other parts of Title 24.

3.2.2 Impact on Market Actors

Table 25 summarizes market actors and suggests outreach and education that might be helpful to support market actors as they prepare for the effective date of the requirements.

Table 25: Impacts on Market Actors and Suggested Training and Education Opportunities

Market Actor	Impact(s)	Suggested Outreach and Education
Owner/Operator[a]	Be aware that condensate return is required and plan for additional costs. Expect higher upfront costs and reduced energy bills. Expect to maintain the condensate return system. May need to complete the NRCC-PRC-E form for new, non-replacement steam loads at existing facilities.	Conduct outreach to owners to improve understanding of the benefits of condensate return and address concerns.
Design Professional[b]	Be aware of new requirements and code triggers when designing process boiler and steam systems. Include condensate return equipment where required and include relevant equipment specifications in design documents. Complete new Process Steam section of NRCC-PRC-E.	Industrial boiler equipment and steam system design firms should be provided training on the energy code including compliance requirements and compliance documentation.
Construction Team[c]	Install condensate return piping as specified in the approved design documents, consistent with standard practice. Complete new section for Process Steam in the NRCI-PRC-E form.	System installers should be provided training on the energy code updates and supporting documentation, compliance requirements, and compliance documentation.
Building Department[d]	Plan Reviewers will have an additional requirement to check when reviewing NRCC and NRCI forms and design documents.	Local building department plan examiners will need education and training to familiarize them with new code language.
Verification Tester[e]	No verification testing is required.	N/A
Manufacturers and Distributors[f]	Additional sales of condensate return piping and equipment.	Manufacturers and distributors will likely not require additional training.

a. Owner/Operator is funding the project and is the primary decision-maker.

b. Design professionals include architects, engineers (mechanical, electrical, plumbing, structural), specification writers, cost estimators, commissioning agents, lighting designers, and energy consultants.

c. Construction team includes general contractors, design-build contractors, installation contractors (e.g., HVAC, plumbing, electrical), commissioning agents, and tradespeople.

d. Building departments include plans reviewers, building inspectors, specialty inspectors, permit counter technicians, and third-party plan review and inspection.

e. Verification testers include commissioning agents, Energy Code Compliance Raters, and Acceptance Test Technicians.

The 2028 CASE Methodology Report presents a quantitative assessment of how changes to the California Building Code impact builders, building designers, and energy consultants. While the analysis in the methodology report is not specific to the code changes presented in this report, this measure focuses on industrial facility owners and operators, design professionals, and building department representatives, since these market actors are expected to experience the most direct impacts from the proposed condensate return requirement. The following section provides a qualitative description of how this specific code change affects various market actors, along with additional quantitative analyses of its potential impacts on building industry subsectors.

Building owners. The proposed code change would have incremental costs and would reduce building owners' utility bills throughout the measure lifetime. See the 2028 CASE Methodology Report for a description of how LSC savings relate to occupant utility bill savings.

Builders. The proposed change would likely affect industrial and commercial builders; however, it would likely not impact firms focused on the construction or retrofitting of residential buildings, utility systems, or public infrastructure. The proposed change would not affect all firms and workers in the industrial and commercial building industries equally; instead, it would primarily affect specific subsectors within the industries. Table 26 shows the commercial and industrial building subsectors that the Statewide CASE Team expects to be impacted by the changes proposed in this measure.

Table 26: Specific Subsectors of the California Commercial and Industrial Building Industry Impacted by Proposed Change to Code/Standard by Subsector in 2025 (Estimated)

Construction Subsector	Establishments*	Employment	Annual Payroll (Billions $)
Industrial Building Construction	278	4,095	$0.5
Nonresidential Structural Steel Contractors	365	11,899	$1.1
Nonresidential Plumbing & HVAC Contractors	2,270	55,182	$5.8
Other Nonresidential Equipment Contractors	580	9,749	$1.1
Nonresidential Site Preparation Contractors	1,147	19,273	$1.9
All Other Nonresidential Trade Contractors	948	17,084	$1.7

Source: (State of California, n.d.)

*An establishment is a single economic unit, typically at one physical location, that engages in one, or predominantly one, type of economic activity for which a single industrial classification may be applied. Many businesses are composed of multiple establishments. US Bureau of Labor Statistics, Handbook of Methods. https://www.bls.gov/opub/hom/cew/concepts.htm

Manufacturers. As discussed in Section 3.3.1.1, multiple manufacturers and installers of condensate return-related equipment are based in California, and these businesses would sell and install additional equipment including pumps, piping, insulation, and tanks. Refer to Section 3.3.4 for more information on the resultant impact on California jobs.

3.2.3 Compliance Software Updates

Review finds no compliance software updates required for this measure proposal.

3.2.4 Cost of Enforcement

The Statewide CASE Team acknowledges that changes to the code will impact enforcement costs. This report is an evaluation of specific measures, and the collective impact of all proposed changes for the 2028 Title 24, Part 6 may represent an increase in training and/or workload for enforcement personnel.

Enforcement costs will include costs to deliver training for enforcement officials to enable them to adequately enforce the proposed measure. This training can leverage current education programs to minimize expenses. Local governments will need to retrain building department staff; however, this practice aligns with the regular triennial code update cycle and is supported by resources such as Energy Code Ace.

The enforcement costs would also include the costs of plan review and inspection. During plan review, the plan examiners would review a new Process Steam section of the NRCC-PRC-E and ensure that the energy features and performance specifications, materials, components, and manufactured devices for the system design identified on the form conform to the requirements of Title 24, Part 1 and Part 6 of the California Code of Regulations and are consistent with the drawings and specifications.

Building inspectors would need to verify compliance with a new requirement for process steam systems in the NRCI-PRC-E form and ensure that the information on the form is consistent with the approved NRCC-PRC-E forms and with what is actually installed.

3.3 Condensate Return – Market and Economic Analysis

3.3.1 Market Structure and Availability

3.3.1.1 Current Market Structure and Availability

Players in the condensate return system market include steam system designers, steam system equipment manufacturers, OEMs, manufacturer representatives, distributors, mechanical contractors, boiler technicians, and water treatment companies. Designers specify condensate return systems that meet steam and boiler system needs. Component manufacturers and OEMs design, manufacture, and supply the system components, including piping, pumps, and condensate return tanks, which are sold both as packaged systems and as individual components. Manufacturer representatives and distributors function as the local sales and distribution channel for the component manufacturers and specialized steam equipment companies. Mechanical contractors manage the physical installation of the system, including any electrical needs for condensate pumps or tank level controls. Equipment manufacturer representatives and mechanical contractors typically perform boiler commissioning and startup.

Condensate return systems are commonly included in standard steam system designs and steam system designers, manufacturers, and vendors are typically familiar with condensate return equipment. The market for condensate return system components is well-established, with multiple manufacturers and suppliers providing designers and contractors with many options for purchase. Table 27 lists companies that the Statewide CASE Team identified as major market actors.

Table 27: Major Condensate Return System Component Manufacturers, Installers, and Vendors

Company	Market Actor Type	Product Offering	Headquartered in California
Armstrong	Manufacturer	Pumps	No
Boiler Supplies	Distributor	Pumps, tanks	No
Calpacific Equipment Company	Vendor	Pumps, tanks	Yes
National Pump Supply	Distributor	Pumps	No
Parker Boiler	Manufacturer	Pumps, tanks	Yes
Solenis	Water Treatment	Chemical water treatment, monitoring and controls	No
Spirax Sarco	Manufacturer	Pumps	No
Rema	Manufacturer	Pumps, tanks	No

The Statewide CASE Team estimates that 30 percent of total steam flow is returned across newly installed qualifying statewide steam capacity in California today. Stakeholder interviewees stated that condensate return rates vary widely between industries and often depend on the application and perceived quality of the steam. Chemical plants and pharmaceutical companies generate clean condensate and have higher condensate recovery rates. Food processing facilities often use steam for direct injection, generating contaminated condensate that cannot be returned to the boiler system. As a result, they typically do not return any condensate.

To account for contaminated condensate in energy savings estimates, the Statewide CASE Team assumed that 75 percent of total steam flow is returned as condensate in the measure case. The remaining 25 percent of generated condensate includes contaminated condensate, return losses, and deaerator steam supply.

The Statewide CASE Team does not foresee this regulation having negative impacts on technology adoption.

3.3.1.2 Market Challenges and Solutions

The Statewide CASE Team does not anticipate any challenges related to product availability with the current market, as multiple vendors and suppliers have decades of experience designing and installing condensate return systems.

The Statewide CASE Team identified potential market adoption barriers to be 1) condensate return system first cost and 2) contaminated steam. Despite the clear fuel, chemical, and water savings provided by condensate return systems, many industrial process facilities do not install condensate return systems or increase the size of a facilities' condensate return system when new steam loads are added to the system.

Industrial facilities often focus on the upfront cost of installing or upgrading condensate return systems and operate with a high barrier for capital expenditure on auxiliary equipment (Energy Efficiency Movement, 2025).

To ensure cost-effectiveness of the proposed requirement, the Statewide CASE Team included the cost of all new equipment in the cost-effectiveness analysis and added measure qualifications based on condensate piping lengths to ensure that only cost-effective combinations of steam loads and return system piping distances need to comply with the proposed requirement. The Statewide CASE Team calculated cost-effectiveness separately for seasonal steam systems and year-round steam systems, as seasonal facilities may experience longer payback periods than facilities that operate year-round as they operate for fewer hours and have less time to recoup the initial installation costs through avoided energy usage. The results of the analysis confirmed that the proposed requirement is cost-effective for seasonal steam systems.

Facility owners may also be concerned with the potential for condensate to make contact with a process and become contaminated and unfit for reuse. To address this concern, condensate return from direct steam injection is not required to be returned to the system for reuse. Any other sources of contaminated condensate, such as mechanical defects or heat exchanger tube leaks, would need to be monitored and repaired for viable condensate return. However, newly installed heat exchangers do not typically experience leaks, as leaks are usually the result of poor water quality or maintenance practices over time. Proper water quality practices, including conductivity monitoring, can ensure newly installed heat exchangers remain in robust condition and prolong the life of existing heat exchangers by minimizing exposure to poor quality water.

During a stakeholder interview, one steam equipment vendor informed the Statewide CASE Team about the prevalence of heat exchanger stall in lower-temperature applications, which leads to operators bypassing steam traps and dumping condensate and steam.[11] The vendor recommended using steam-motive pump traps to prevent heat exchanger stall. The Statewide CASE Team recommends further consideration of heat exchanger stall and steam-motive pump traps in future code cycles.

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[11] According to this stakeholder, temperature-controlled heat exchangers serving lower-temperature processes, such as 180°F to 190° hot water routinely enter into vacuum on the steam side. The steam trap then cannot discharge condensate, and water accumulates in the heat exchanger in a condition known as stall. The control valve then begins hunting and water hammer results from thermal shock. Operators then bypass the steam trap to protect the process, which wastes significant condensate, flash steam, and live steam. One solution for these applications is the use of steam-motive pump traps, which are sold by multiple major manufacturers. When a steam-motive pump trap cannot discharge condensate normally and liquid accumulates inside of it, a high-limit switch is tripped which introduces live steam to force the condensate out of the trap.

3.3.2 Design and Construction Practices

3.3.2.1 Current Design and Construction Practices

Condensate return is a widely accepted best practice for steam systems, and DOE has included condensate return in the steam tip sheets for over a decade (DOE, 2012). Condensate return systems typically consist of condensate return piping, collection tanks, and pumps. These systems require adequate physical space for installation but can typically be accommodated at facilities that add new steam loads. Condensate piping is smaller than steam piping, and the tank and pump are sized for minimum transient time, so heat loss from the condensate is relatively small. Condensate return piping is generally made of stainless steel to prevent carbonic acid corrosion and should always be insulated to minimize heat loss and maximize energy recovery in a steam system (Paffel, Best Practices for Condensate Piping , 2011). Piping should also be designed for two-phase flow to account for the creation of flash steam in condensate headers. Connections to the condensate header should only be made on a horizontal header and directly on top of the header to prevent water hammering as a result of flash steam entering directly into the condensate space of a header from a piping connecting on to the side or bottom of the header (Paffel, Best Practices for Condensate Piping , 2011). To further avoid the potential of water hammer, low pressure system condensate return lines should be sloped to allow for drainage and avoid condensate collection in the pipe (Paffel, Best Practices for Condensate Piping , 2011). For longer distances or higher-pressure situations, gravity sends condensate return into a receiver tank, where it is then pumped back to the condensate header. Condensate receivers are sold alone or with pumps and are offered in various configurations, such as cylindrical and rectangular, and can be installed at various elevations to meet pump needs (Sengheiser, 2021). Condensate return pumps come in two main forms: electrical and pressure operated (Paffel, Best Practices for Condensate Piping , 2011). Electrical pumps consist of a condensate receiver and a float switch that is tripped by condensate level, activating the pump to empty the receiver (Paffel, Best Practices for Condensate Piping , 2011). Pressure operated pumps use steam or air as the pumping motive, which is activated by a mechanical or electrical valve based on condensate level. Both types of pumps can be sold as individual pumps (simplex) or a set of pumps (duplex), allowing for pump redundancy (Paffel, Best Practices for Condensate Piping , 2011). Condensate return systems are common in boiler and steam system design today and the proposed changes would come with no anticipated impacts to current design and construction best-practices.

3.3.2.2 Health and Safety Considerations

The proposed code change does not alter any existing federal, state, or local regulations pertaining to safety and health, including rules enforced by the California DOSH. All existing health and safety rules would remain in place. Complying with the proposed code change is not anticipated to have adverse impacts on the safety or health of occupants or those involved with the construction, commissioning, and maintenance of the site. The proposed code change would reduce photochemical smog and improve air quality near the facility by reducing boiler fuel consumption and associated emissions.

3.3.2.3 Design and Construction Challenges and Solutions

The Statewide CASE Team identified two potential design and construction challenges for the condensate return measure: 1) pump reliability, and 2) long piping distances between the steam trap serving the load to the condensate return tank or the deaerator.

During an interview with the Statewide CASE Team, a boiler and steam systems representative stated that the main reason condensate is not always returned at a facility that has a condensate return system is that there are issues with the condensate pump. The condensate pump may not be sized correctly or may not operate as designed. The pump could fail to adequately drain a condensate receiver, leading to condensate tank overflow, or it could run continuously and eventually break. Operators often do not consider condensate pumps to be critical equipment and therefore may not always prioritize repair of these pumps. The Statewide CASE Team included the costs of pump maintenance and full replacement in the cost-effectiveness calculations to ensure maintenance costs are not a barrier to measure viability.

The distance of pipe runs between the steam trap serving the load to the condensate return tank or the deaerator may vary between sites. Sites with longer distances incur higher incremental measure costs due to the need for additional piping. To ensure measure cost-effectiveness, new process steam loads are subject only to the condensate return requirement if the distance between the new steam load and the nearest condensate tank or the serving boiler is less than the maximum linear distance specified in the code trigger table. To establish maximum specified linear distances, the Statewide CASE Team calculated pipe lengths for select steam load sizes that achieve simple payback periods[12] of under 10 years, based on combined energy and water cost savings. Details on the resulting payback periods by boiler capacity are shown in Table 43. The Statewide CASE Team evaluated the maximum cost-effective condensate return piping lengths separately for year-round and seasonal facilities, as seasonal facilities have longer payback periods due to fewer annual operating hours. The maximum cost-effective lengths for seasonal facilities were used to set the maximum qualifying lengths in the code trigger table, ensuring the proposed requirements remain cost-effective across boilers with varying operating hours.

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[12] The simple payback calculations account for energy and water savings (using a conservative $0.90 per therm of natural gas and $3.50 per thousand gallons of water) and do not discount the costs or benefits to their present values.

Table 5 in Section 2.2.2 describes workforce trainings that could support effective design, installation, and commissioning.

3.3.3 Energy Equity and Environmental Justice

Each measure in this CASE Report was evaluated for ESJ impacts using 4 criteria: cost, health, resiliency, and comfort. The details of that evaluation can be found in Section 1.4 and the 2028 CASE Methodology Report.

The Statewide CASE Team does not expect any impact on the health and safety of ESJ communities, or on their disaster preparedness. The comfort of ESJ communities is unlikely to be impacted by the proposed code changes.

The use of condensate return in steam boiler systems would reduce boiler fuel consumption and avoid the associated emissions from burning fuel. The value of improved air quality resulting from the proposed code changes is augmented by the fact that many industrial facilities are disproportionately located near ESJ communities and Low- and Moderate-Income (LMI) housing. As a result, the Statewide CASE Team expects that ESJ communities may experience a disproportionate improvement in air quality over time from this proposed measure.

3.3.4 Impacts on Jobs and Businesses

The Statewide CASE Team does not anticipate significant employment or financial impacts on any particular sector of the California economy from this proposed measure. However, the proposed change may have modest impacts on employment in California. The Statewide CASE Team anticipates that the proposed change would directly and indirectly affect statewide employment and economic output through its impact on builders, designers, energy consultants, and building inspectors. Table 28, Table 29, and Table 30 outline the statewide implications for these job categories. For more information on the Statewide CASE Team's economic impacts methodology, see the 2028 CASE Methodology Report.

The Statewide CASE Team does not anticipate that the proposed changes would lead to the creation of new types of jobs or the elimination of existing types of jobs. In other words, the Statewide CASE Team's proposed change would not result in economic disruption to any sector of the California economy. Rather, it would lead to modest increases in the employment of existing jobs.

Table 28: Estimated Impact that Adoption of the Proposed Measure would have on the California Nonresidential Construction Sector

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by Commercial Builders)	62.6	$4,977,785	$7,494,555	$16,215,936
Indirect Effect (Additional spending by firms supporting Commercial Builders)	36.5	$2,877,381	$4,939,828	$8,648,258
Total Economic Impacts	**99.1**	**$7,855,166**	**$12,434,383**	**$24,864,194**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.

Table 29: Estimated Impact that Adoption of Proposed Measure would have on California Building Designers and Energy Consultant Sectors

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by building designers and energy consultants)	0.4	$40,836	$40,427	$63,898
Indirect Effect (Additional spending by firms supporting building designers and energy consultants)	0.1	$12,159	$16,898	$27,203
Total Economic Impacts	**0.5**	**$52,995**	**$57,325**	**$91,101**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.

Table 30: Estimated Impact that Adoption of the Proposed Measure would have on California Building Inspectors

Type of Economic Impact	Employment (Jobs)	Labor Income	Total Value Added	Output
Direct Effects (Additional spending by building inspectors)	0.016	$1,848	$2,191	$2,663
Indirect Effect (Additional spending by firms supporting building inspectors)	0.002	$171	$267	$464
Total Economic Impacts	**0.018**	**$2,019**	**$2,458**	**$3,127**

Source: Statewide CASE Team analysis of data from the IMPLAN modeling software.

The proposed change represents a modest adjustment, which is not expected to excessively burden or competitively disadvantage California businesses, nor is it expected to lead to a competitive advantage for California businesses. Therefore, the Statewide CASE Team does not expect the proposed code changes to result in the creation of new businesses or the elimination of existing ones.

The proposed code changes would apply to all businesses operating in California, regardless of whether the business is incorporated inside or outside of the state. Therefore, the Statewide CASE Team does not anticipate that the proposed changes would have an advantageous or an adverse effect on the competitiveness of California businesses.

The Statewide CASE Team derived a reasonable estimate of the change in investment by California businesses based on the estimated change in economic activity associated with the proposed measure and its expected effect on business income. The Statewide CASE Team's IMPLAN modeling resulted in an estimated $1,719,671 increase in California business income due to the proposed code change. The Statewide CASE Team assumed that net business investment is positively correlated with business income and that a portion of business income will be allocated to net business investment.

To estimate the portion of business income that would be allocated to net investment, the Statewide CASE Team analyzed national data on corporate profits and net capital investment by businesses that expand a firm's capital stock (referred to as net private domestic investment, or NPDI). As Table 31 shows, between 2020 and 2024, NPDI as a percentage of corporate profits ranged from a low of 18 percent in 2020 due to the worldwide economic slowdowns associated with the COVID-19 pandemic, to a high of 28 percent in 2022, with an average of 23 percent. While only an approximation of the proportion of business income used for net capital investment, it provides a reasonable estimate of the proportion of proprietor income that business owners would reinvest into expanding their capital stock.

Table 31: Net Private Domestic Investment and Corporate Profits, U.S.

Year	Net Domestic Private Investment by Businesses, Billions of Dollars	Corporate Profits After Taxes, Billions of Dollars	Ratio of Net Private Investment to Corporate Profits (Percent)
2020	$389	$2,212	18%
2021	$545	$2,888	19%
2022	$825	$2,951	28%
2023	$836	$3,069	27%
2024	$885	$3,441	26%
5-Year Average	**-**	**-**	**23%**

Source: (Federal Reserve Economic Data (FRED) n.d.)

Given the estimated total increase in California business income and net business investment ratio described above, the Statewide CASE Team estimates the proposed code change would result in a $403,674 increase in net private investment by California businesses.

3.3.5 Economic and Fiscal Impacts

The Statewide CASE Team does not anticipate that the economic impacts associated with the proposed measure would lead to a significant change (increase or decrease) in investment, directly or indirectly, in any affected sectors of California's economy. The proposed change would not result in economic disruption to any sector of the California economy. For more information on the Statewide CASE Team's economic and fiscal impacts methodology, see the 2028 CASE Methodology Report.

Adoption of this code change proposal would result in relatively modest economic impacts through additional direct spending by or on industrial contractors, energy consultants, and building inspectors. The Statewide CASE Team does not anticipate that money saved by businesses or other organizations affected by the proposed 2028 code cycle regulations would result in additional spending by those businesses.

3.3.5.1 Effects on the State General Fund, State Special Funds, and Local Governments

The Statewide CASE Team does not expect the proposed code changes to have a measurable impact on California's General Fund, any state special funds, or local government funds.

Cost to State: The state government already has a budget for code development, education, and compliance enforcement. While the state government would be allocating resources to update the Title 24, Part 6 Standards, including updating education and compliance materials and responding to questions about the revised requirements, these activities are already covered by existing state budgets. The costs for the state government are small when compared to the overall cost savings and policy benefits associated with the code change proposals. State buildings do not typically operate process boilers of qualifying size and so would not be directly impacted by this proposed measure.

Cost to Local Governments: All proposed code changes to Title 24, Part 6 would result in changes to compliance determinations. Local governments would need to train building department staff on the revised Title 24, Part 6 Standards. While this retraining is an expense to local governments, it is not a new cost associated with the 2028 code change cycle. The building code is updated on a triennial basis, and local governments plan and budget for retraining every time the code is updated. There are numerous resources available to local governments to support compliance training that can help mitigate the cost of retraining, including tools, training, and resources provided by the

IOU Codes and Standards program (such as Energy Code Ace). As noted in Section 3, the Statewide CASE Team considered how the proposed code change might impact various market actors involved in the compliance and enforcement process and aimed to minimize negative impacts on local governments.

3.3.5.2 Mandates on Local Agencies or School Districts

There are no relevant mandates to local agencies or school districts because local agencies and schools do not typically operate process boilers of qualifying size.

3.3.5.3 Costs to Local Agencies or School Districts

There are no costs to local agencies or school districts because local agencies and schools do not typically operate process boilers of qualifying size.

3.3.5.4 Costs or Savings to Any State Agency

There are no costs or savings to any state agencies because these agencies do not typically operate process boilers of qualifying size.

3.3.5.5 Other Non-Discretionary Cost or Savings Imposed on Local Agencies

There are no added non-discretionary costs or savings to local agencies because local agencies do not typically operate process boilers of qualifying size.

3.3.5.6 Costs or Savings in Federal Funding to the State

The Statewide CASE Team did not identify any costs or savings to federal funding provided to the state.

3.4 Condensate Return – Cost Effectiveness

3.4.1 Cost Effectiveness Methodology

The Statewide CASE Team collaborated with CEC staff to confirm that the cost-effectiveness methodology aligns with CEC guidelines, including cost inclusion parameters. The 2028 CASE Methodology Report and Appendix A provide reproducibility details.

Per California Law (Public Resources Code 25000), a measure is considered cost effective if its BCR is 1.0 or greater, amortized over the economic life of the structure. The Statewide CASE Team calculates BCR by dividing total dollar benefits by total dollar costs over a 30-year analysis period.

Benefits are based on LSC, which assigns an hourly dollar value to energy use. LSC hourly factors weigh the long-term value of each hour differently, where times of peak demand are valued more than off-peak hours. These factors are not utility rates, forecasts, or bill estimates. The CEC develops and publishes LSC hourly conversion factors for each code cycle.

Total measure costs include first costs and ongoing maintenance costs assessed over the 30-year period. Benefits and costs are evaluated incrementally, relative to the most recently adopted Energy Code.

3.4.2 Energy and Energy Cost Savings Results

To analyze the energy savings from the proposed condensate return requirement, the Statewide CASE Team calculated the difference in energy consumption between the baseline (a steam system returning 30 percent of its condensate) and the measure case (a steam system returning 75 percent of its condensate). Savings calculations were completed for two separate components driving savings:

- Deaerator preheating savings: Replacing cold make-up water with warm or hot returned condensate reduces the energy required to heat the deaerator. Returned condensate is typically at 200°F, while cold make-up water is around 65°F. The energy savings calculations are based on the amount of energy required to heat the water in the baseline case compared with the measure case and account for temperature losses due to condensate pipe length.
- Blowdown reduction: Replacing make-up water (which contains dissolved solids) with condensate (which is effectively distilled water) reduces the quantity of water that needs to be blown down from the boiler and replaced. Blowdown for a 100 psig boiler reaches 338°F prior to discharge, and reducing water lost to blowdown reduces energy losses by avoiding the need to heat more make-up water. The Statewide CASE Team first calculated the difference in water lost to blowdown between the baseline case and the measure case and then calculated the energy that would have been required to heat that water.

Natural gas and water savings increase as the associated steam boiler capacity increases because the total volume of returned condensate increases. Savings also scale with boiler operation; boilers that operate infrequently throughout the year due to seasonal loads will experience lower energy and water savings. Due to this variance, the Statewide CASE Team calculated annual savings for boilers with seasonal loads separately from boilers with more typical annual loads. Calculations for boilers operating annually assumed 6,500 operating hours per year at 40 percent load, while calculations for seasonal boilers assumed 2,400 operating hours per year (primarily July through October) at 80 percent load. The Statewide CASE Team based the operating hours and load factor assumptions on analysis of data from a survey of 128 California steam-using sites in IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025). Since boiler and flash steam recovery systems are frequently sized for higher capacities than they typically operate at, the Statewide

CASE Team applied an 80 percent load assumption for all boilers, year-round and seasonal, when calculating steam loads for the cost analysis.

Savings from condensate return should stay constant over the measured lifetime. However, components of the condensate return system components could fail, reducing the energy savings from the measure.

Per-unit savings for the first year are expected to be 186,300 kBtu per MMBtu/h of boiler capacity for year-round boilers and 137,900 kBtu per MMBtu/h of boiler capacity for seasonal boilers, as shown in Table 32. The energy and water savings scale linearly with boiler capacity, so the per-unit savings are the same for all boiler capacities. No electric savings or demand reductions are associated with this measure. The per-unit energy savings of this measure are not impacted by climate zone and are the same across new construction, additions, or alterations.

While energy savings do not differ across climate zones, the LSC factors do vary slightly by climate zone. Table 33 presents total per-unit energy cost savings for newly added boilers in terms of LSC savings realized over a 30-year period, in 2029 PV$ for year-round and seasonal boilers by climate zone.

Table 32: First Year Natural Gas Savings (kBtu) Per MMBtu/h of Boiler Capacity – Condensate Return

Boiler Category (All Boiler Capacities)	First Year Natural Gas Savings (kBtu)
Year-Round	186,300
Seasonal	137,900

Table 33: Total 30-Year LSC Savings (2029 PV$) Per MMBtu/h of Boiler Capacity – Condensate Return

Climate Zone	Year-Round Boilers	Seasonal Boilers
1	154,287	101,390
2	154,287	101,390
3	154,287	101,390
4	154,287	101,390
5	154,287	101,390
6	156,143	101,530
7	155,686	101,505
8	156,143	101,530
9	156,143	101,530
10	156,143	101,530
11	154,287	101,390
12	154,287	101,390
13	154,287	101,390
14	156,143	101,530
15	156,143	101,530
16	156,143	101,530

3.4.3 Incremental First Cost

The Statewide CASE Team assumes the baseline case for calculating the incremental costs of this measure to be a new steam system with no condensate return. Incremental first costs are consistent between newly added steam loads at new industrial facilities (i.e., new construction) and newly added steam loads at existing industrial facilities (i.e., additions and alterations).

The incremental first cost for a condensate return system includes the cost of purchasing and installing condensate return piping, piping insulation, a condensate tank, and condensate pumps. Installation labor costs are the largest contributor to first costs. The costs of piping, piping insulation, and equipment such as tanks, valves, and fittings are also significant.

The Statewide CASE Team obtained condensate return piping, insulation, tank and pump costs from the RSMeans database using pricing data from April 2025. Installation cost estimates, including the costs of commissioning and compliance verification, were based on field experience and historical project costs. All incremental first costs are expected to increase with inflation.

When sized for larger steam loads, condensate return equipment is larger and more expensive. Additionally, each additional steam load incurs the cost of an additional pump. The Statewide CASE Team assumed an increasing number and size of steam loads at the boiler as boiler capacity increases, from two steam loads up to 12 for the largest boilers. When selecting the pipe lengths to calculate incremental measure costs, the Statewide CASE Team estimated that pipe lengths equivalent to 75 percent of the maximum length from the code trigger table represent a conservative average of real-world installed piping lengths based on engineering judgement.

Table 34 shows the total estimated incremental measure first costs by boiler capacity. Additional details on cost assumptions, including a detailed cost breakdown of the condensate return measure first costs for a boiler with an input capacity of 12 MMBtu/h (Table 50).

Table 34: Condensate Return System Incremental First Cost by Boiler Capacity

Boiler Capacity	Condensate Return System First Cost	Condensate Return System First Cost Per Unit
10-15 MMBtu/h	$145,264	$12,139
15-25 MMBtu/h	$253,362	$13,034
25-50 MMBtu/h	$380,043	$11,666
50-100 MMBtu/h	$896,345	$12,682
100-200 MMBtu/h	$1,692,933	$11,862
200+ MMBtu/h	$4,931,741	$6,672

3.4.3 Incremental Maintenance and Replacement Costs

The incremental maintenance and replacement costs for a condensate return system include the costs of insulation maintenance and pump and tank replacement. Maintenance costs for the steam piping itself were not included in the cost analysis, as the lifespan of stainless steel and carbon steel piping ranges from 20 years to over 50 years (Pak Industrial Services, n.d.) and the piping is not expected to be replaced in the 30-year analysis period. A detailed breakdown of incremental maintenance and replacement costs is provided in Table 49.

Condensate return lines are insulated to minimize heat loss from the condensate being returned to the boiler for reuse. Insulating steam piping can reduce energy loss to the atmosphere by up to 90 percent, making piping insulation maintenance crucial to conserving energy and reducing heat loss over time (DOE, 2012). Insulation damage is usually caused by selecting the wrong type or quantity of insulation for the process, improper installation practices, physical damage (such as walking or climbing on uninsulated pipes), or corrosion or contamination caused by exposure to process or steam leaks (Multiservice Industrial, 2022). Maintenance and replacement of damaged piping insulation can be performed by general maintenance staff and are important to ensure the measure savings persist throughout the 30-year analysis period.

The incremental cost of insulation maintenance is based on an assumed insulation degradation rate of one percent per year. The Statewide CASE Team assumed that insulation maintenance occurs every 10 years, with costs estimated as a proportional share of the original installation cost based on the amount of insulation replaced. The Statewide CASE Team based the maintenance and replacement frequency estimates on the 2025 Process Pipe Load CASE Report (Amoni & Alkhatib, 2023).

The replacement frequency for typical pumps per DEER data is 15 years (California Electronic Technical Reference Manual, 2013). The Statewide CASE Team's measure costs include condensate pump replacement at a conservative frequency of 10 years, or twice during the 30-year analysis period. Condensate tanks last between 15 and 50 years. (Savannah Tank and Equipment Corporation, n.d.). The maintenance cost for the condensate return measure includes the cost of condensate tank replacement in year 20. The Statewide CASE Team used the same costs for initial equipment purchase and replacement.

For detailed maintenance costs, see Appendix A. Descriptions of the estimation of present value of maintenance and replacement costs are provided in the 2028 CASE Methodology Report.

3.4.4 Cost Effectiveness

Results of the per-unit cost-effectiveness analyses are presented in Table 35 and Table 36. The results do not vary between new construction, additions, and alterations. The proposed code change is cost effective in every climate zone and for additions and alterations in addition to new construction. Because changes in LSC savings vary only slightly by climate zone, Table 35 presents LSC savings for Climate Zone 1.

In the tables below, all values are presented in 2029 PV$. Benefits represent 30-year LSC savings and other savings, including incremental first-cost savings if the proposed first cost is less than the current first cost, incremental maintenance cost savings if the proposed maintenance costs are less than the current maintenance costs, and incremental residual value if the proposed residual value is greater than the current residual value at the end of the 30-year period of analysis. Costs represent the total incremental PV cost, including incremental equipment, replacement, and maintenance costs over the period of analysis. The analysis treats a negative incremental maintenance cost as a positive benefit. If total incremental costs are zero, the BCR is considered infinite. Costs and other savings are discounted at a real (inflation-adjusted) three percent rate. If there are no total incremental PV costs, the BCR is infinite. A BCR of "NA" indicates that there is no boiler capacity in that climate zone that would be impacted by the proposed requirement.

The BCR values indicate that condensate return systems are highly cost-effective investments with strong society-level benefits. However, the LSC metric is a system-level valuation metric rather than a prediction of customer utility bills or customer-specific benefits. Industrial decision-makers are likely to evaluate investment decisions using their anticipated facility energy rates, operational considerations, maintenance impacts, and internal capital criteria. Industrial energy costs for individual facilities may be materially different depending on negotiated service agreements.

Based on simple payback calculations with market energy prices for industrial customers[13], the expected payback periods based on energy savings range from three to seven years, depending on boiler capacity and frequency of operation. While the return on investment is clear, industrial facility owners often operate with a high barrier for capital expenditure on auxiliary equipment, and typical investments for industrial process equipment have payback periods of one to three years. (Energy Efficiency Movement, 2025).

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[13] Simple payback calculations used natural gas prices of $1.30/therm, based on data from EIA and confirmed by IAC data from industrial sites in California from 2024 and 2025 (DOE 2026, EIA 2026).

Table 35: 30-Year Cost-Effectiveness Summary Per MMBtu/h of Boiler Capacity – Condensate Return

Boiler Category	Benefits LSC Savings + Other PV Savings (2029 PV$)	Costs Total Incremental PV Costs (2029 PV$)	Benefit-to-Cost Ratio
Year-Round Boiler 10-15 MMBtu/h	$155,226.24	$15,155.12	10.24
Year-Round Boiler 15-25 MMBtu/h	$155,213.07	$15,366.36	10.10
Year-Round Boiler 25-50 MMBtu/h	$155,072.15	$13,725.00	11.30
Year-Round Boiler 50-100 MMBtu/h	$154,394.71	$14,382.62	10.73
Year-Round Boiler 100-200 MMBtu/h	$154,735.21	$13,263.16	11.67
Year-Round Boiler 200+ MMBtu/h	$155,579.07	$7,435.78	20.92
Seasonal Boiler 10-15 MMBtu/h	$101,461.15	$15,155.12	6.69
Seasonal Boiler 15-25 MMBtu/h	$101,459.92	$15,366.36	6.60
Seasonal Boiler 25-50 MMBtu/h	$101,449.28	$13,725.00	7.39
Seasonal Boiler 50-100 MMBtu/h	$101,397.79	$14,382.62	7.05
Seasonal Boiler 100-200 MMBtu/h	$101,423.51	$13,263.16	7.65
Seasonal Boiler 200+ MMBtu/h	$101,487.37	$7,435.78	13.65

Table 36: Benefit-to-Cost Ratio – Condensate Return

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round 10-15 MMBtu/h	10.2	10.2	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3
Year-Round 15-25 MMBtu/h	N/A	10.0	10.0	10.0	10.0	10.2	10.1	10.2	10.2	10.2	10.0	10.0	10.0	10.2	10.2	10.2
Year-Round 25-50 MMBtu/h	11.2	11.2	11.2	11.2	11.2	11.4	11.3	11.4	11.4	11.4	11.2	11.2	11.2	11.4	11.4	11.4
Year-Round 50-100 MMBtu/h	N/A	10.7	10.7	10.7	10.7	10.9	10.8	10.9	10.9	10.9	10.7	10.7	10.7	10.9	10.9	10.9
Year-Round 100-200 MMBtu/h	N/A	11.6	11.6	11.6	N/A	11.8	N/A	11.8	11.8	11.8	11.6	11.6	11.6	11.8	11.8	11.8
Year-Round 200+ MMBtu/h	20.7	20.7	20.7	20.7	N/A	21.0	N/A	21.0	21.0	21.0	20.7	20.7	20.7	21.0	21.0	21.0
Seasonal 10-15 MMBtu/h	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Seasonal 15-25 MMBtu/h	N/A	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Seasonal 25-50 MMBtu/h	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Seasonal 50-100 MMBtu/h	N/A	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.0	7.0	7.0	7.1	7.1	7.1
Seasonal 100-200 MMBtu/h	N/A	7.6	7.6	7.6	N/A	7.7	N/A	7.7	7.7	7.7	7.6	7.6	7.6	7.7	7.7	7.7
Seasonal 200+ MMBtu/h	13.6	13.6	13.6	13.6	N/A	13.7	N/A	13.7	13.7	13.7	13.6	13.6	13.6	13.7	13.7	13.7

3.5 Condensate Return – Statewide Impacts

3.5.1 Statewide Energy and Energy Cost Savings

To determine statewide savings from the proposed condensate return measure, the Statewide CASE Team first used a statewide boiler inventory of local AQMD boiler permits to estimate boiler capacities, thereby quantifying installations by boiler capacity bins to quantify the total statewide steam boiler capacity by boiler capacity bins. (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025). Appendix C contains more information on these data. The Statewide CASE Team then refined the statewide capacity to account for Title 24, Part 6 purview and measure qualification, making the following changes:

1. Removed boilers with input capacities under 10 MMBtu/h and hot water boilers;
2. Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements;
3. Removed 10 percent of remaining boiler capacity to account for steam loads that would not qualify for the requirement via the code trigger table; and
4. Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.
    - The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes represents the Existing Boilers Stock. The analysis included boilers in the healthcare, education, lumber, and refinery sectors in the statewide capacity totals.

To estimate the capacity of new steam loads installed annually, the Statewide CASE Team calculated four IPGRs: 1) year-round new construction, 2) year-round additions and alterations, 3) seasonal new construction, and 4) seasonal additions and alterations. New construction includes all steam loads at new facilities and additions and alterations includes new steam loads at existing facilities. Appendix C includes additional details on how the Statewide CASE Team calculated the IPGRs. The annual new construction and additions and alterations forecasts are equivalent to the Existing Steam Boiler Stock multiplied by the IPGRs for each category. The Statewide CASE Team then multiplied the per-unit measure savings by the new construction growth rate forecast and the additions and alterations growth rate forecast to obtain first-year statewide savings.

The Statewide CASE Team calculated the energy and water savings using a baseline case of 30 percent condensate return to represent the naturally occurring market adoption of condensate return in the savings estimates. Therefore, the per-unit savings multiplied by the growth forecasts already account for the share of new qualifying steam systems that would install condensate return systems without the proposed requirement enacted. Appendix C presents the assumptions on the percentage of the total construction forecast that the proposed measure would impact. The 2028 CASE Methodology Reports include further explanation on how statewide savings are calculated, including the methodology and context for estimating the current market-share rate and statewide energy and energy cost savings.

Table 37 presents the first-year statewide energy and LSC savings from new steam loads at newly constructed industrial facilities by climate zone, and Table 38 does the same for new steam loads that are part of additions or alterations to existing facilities. Table 39 presents first-year statewide savings from new construction, additions, and alterations.

Table 37: Statewide Energy and LSC Impacts – New Construction

Climate Zone	Statewide New Construction Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	0.57	-	-	0.00	0.09	$0.08
2	1.37	-	-	0.00	0.22	$0.21
3	9.14	-	-	0.02	1.45	$1.39
4	3.70	-	-	0.01	0.59	$0.56
5	0.75	-	-	0.00	0.12	$0.12
6	6.18	-	-	0.01	0.97	$0.95
7	1.69	-	-	0.00	0.27	$0.26
8	9.50	-	-	0.02	1.49	$1.46
9	11.68	-	-	0.02	1.84	$1.79
10	7.88	-	-	0.01	1.24	$1.21
11	4.23	-	-	0.01	0.66	$0.63
12	27.38	-	-	0.05	4.35	$4.18
13	30.52	-	-	0.06	4.86	$4.67
14	4.15	-	-	0.01	0.65	$0.63
15	2.09	-	-	0.00	0.33	$0.32
16	1.11	-	-	0.00	0.17	$0.17
Total	**121.92**	**-**	**-**	**0.22**	**19.29**	**$18.63**

Table 38: Statewide Energy and LSC Impacts – Additions and Alterations

Climate Zone	Statewide Additions and Alterations Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	5.09	-	-	0.01	0.80	$0.76
2	12.33	-	-	0.02	1.95	$1.87
3	82.26	-	-	0.15	13.05	$12.52
4	33.30	-	-	0.06	5.27	$5.06
5	6.73	-	-	0.01	1.08	$1.04
6	55.59	-	-	0.10	8.75	$8.55
7	15.17	-	-	0.03	2.40	$2.36
8	85.48	-	-	0.16	13.42	$13.10
9	105.14	-	-	0.19	16.52	$16.13
10	70.93	-	-	0.13	11.15	$10.89
11	38.03	-	-	0.07	5.97	$5.71
12	246.38	-	-	0.46	39.14	$37.58
13	274.67	-	-	0.51	43.71	$41.99
14	37.35	-	-	0.07	5.85	$5.70
15	18.85	-	-	0.03	2.96	$2.88
16	10.02	-	-	0.02	1.57	$1.53
Total	**1,097.32**	-	-	**2.02**	**173.59**	**$167.67**

Table 39: Statewide Energy and LSC Impacts – New Construction, Additions, and Alterations

Construction Type	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction (MW)	First -Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
New Construction	-	-	0.22	19.29	$18.63
Additions & Alterations	-	-	2.02	173.59	$167.67
Total	**-**	**-**	**2.25**	**192.88**	**$186.30**

3.5.2 Statewide Greenhouse Gas Emissions Reductions

Table 40 presents the estimated first-year avoided GHG emissions resulting from the proposed code change. In this initial year, the Statewide CASE Team expects to avoid 11,731 metric tons of CO_2e emissions. These reductions, along with their associated monetary value, were calculated using hourly GHG emissions factors published alongside the LSC hourly factors and source energy hourly factors in the research versions of the California Building Energy Code Compliance Software (CBECC), as well as data from the CEC's 2028 Metrics Report. See the 2028 CASE Methodology Report for additional information.

Table 40: First-Year Statewide GHG Emissions Impacts

Construction Type	Avoided GHG Emissions from Electricity Savings (Metric Tons CO_2e)	Avoided GHG Emissions from Natural Gas Savings (Metric Tons CO_2e)	Total Avoided GHG Emissions (Metric Ton CO_2e)	Total Monetary Value of Avoided GHG Emissions ($)
New Construction	0	1,173	1,173	$190,588.43
Additions & Alterations	0	10,558	10,558	$1,715,295.85
Total	**0**	**11,731**	**11,731**	**$1,905,884.28**

3.5.3 Statewide Water Use Impacts

The Statewide CASE Team calculated water savings by adding the increase in condensate flow and the decrease in blowdown flow between the baseline and proposed cases. Appendix A provides further calculation details.

Table 41 presents the statewide impact on water use from the proposed measure. The 2028 CASE Methodology Report includes additional information on the embedded electricity savings estimates, which assume embedded energy factors of 5,440 kWh per million gallons of water for indoor use and 3,280 kWh per million gallons of water for outdoor water use (SBW Consulting, Inc., 2022).

Table 41: Impacts on Water Use and Embedded Electricity in Water

Impact	On-Site Indoor Water Savings (Gallons/Year)	On-site Outdoor Water Savings (Gallons/Year)	Embedded Electricity Savings (kWh/Year)
Average Per MMBtu/h of Boiler Capacity Impacts	119,543	-	650
First-Year Statewide Impacts for New Construction	13,990,043	-	76,106
First-Year Statewide Impacts for Additions and Alterations	125,910,391	-	684,953
Total First-Year Statewide Impacts	**139,900,434**	**-**	**761,058**

3.5.4 Statewide Material Impacts

Condensate return piping, pumps, and tanks are typically made from carbon steel and stainless steel (Plant Engineering, 2011). The proposed requirement would increase demand for steel at industrial sites. Because piping contributes significantly more steel than pumps and tanks in a condensate return system, only piping was considered for material impacts, using the same lengths as the lengths used to calculate measure costs. Table 42 summarizes the steel impact. The 2028 CASE Methodology Report provides more information on the Statewide CASE Team's methodology and assumptions used to calculate embodied GHG emissions.

Table 42: First-Year Statewide Impacts on Material Use

Material	Impact	Per-Unit Impacts (Pounds per MMBtu/h)	First-Year Statewide Impacts (Pounds)	Embodied GHG emissions saved (Metric Tons CO2e)
Mercury	No change	-	-	-
Lead	No change	-	-	-
Copper	No change	-	-	-
Steel	Increase	137	167,496	-102
Plastic	No change	-	-	-
TOTAL	**Increase**	**137**	**167,496**	**-102**

3.5.5 Environmental Impacts

The Statewide CASE Team has considered opportunities to minimize the proposal's environmental impact, including an evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

The proposed measure would reduce water use, energy consumption, and ozone production. Condensate return systems reduce water use by replacing fresh make-up water with returned condensate. Fresh make-up water requires additional heating from the boiler, so replacing it with recovered condensate decreases boiler fuel consumption. The reduction in energy consumption from decreased combustion would also improve local air quality and reduce ozone and local photochemical smog, as natural gas combustion produces nitrogen oxides (NOx), which are chemical precursors to ozone (Chen, Omotesho, & Johnson, 2025).

3.5.6 Other Non-Energy Impacts

In addition to reducing water use, flash steam recovery reduces the use of chemicals used to treat incoming boiler feedwater.

3.6 Condensate Return – Proposed Code Language

3.6.1 Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes follow the restructured 2025 Building Energy Efficiency Standards and are marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

New to the 2028 energy code is to *italicize defined terms* when the terms are being used in its defined context. In-line comments that are not part of the proposed code language but are used to help describe the purpose of what is proposed are included *with greyed highlight and italics.*

Markups are provided to the restructured 2025 Energy Code that the CEC developed in response to feedback that aligning the structure of Title 24, Part 6 with other parts of the California Building Standards Code (Title 24) would improve readability, usability, and navigation.[8] New section numbers are shown as bold followed square brackets that document the section in the 2025 Title 24, Part 6 section numbers prior to the restructuring. For example, "**Section 601.1** [Section 130.0(a)] **General"** contains the content that is in the current Section 130.0(a).

Posting the proposed code language in this format is useful as it helps describe how the Energy Code changes proposed for nonresidential occupancies are isolated from the requirements for residential occupancies which are prohibited from being changed until the 2031 code cycle by Assembly Bill 130.

3.6.2 Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

3.6.3 Energy Code (Title 24, Part 6)

SECTION 100 – SCOPE AND ADMINISTRATION

100.4 [Section 100.0(e)] **Sections applicable.**

Covered processes associated with *nonresidential, hotel/motel, or multifamily occupancies* shall comply with the applicable requirements of Table 100.4-B.

TABLE 100.4-B [Table 100.0-A] APPLICATION OF STANDARDS COVERED PROCESSES[14]

Application	Mandatory (Newly Constructed)	Prescriptive (Newly Constructed)	Performance (Newly Constructed)	Additions/ Alterations
General	100 (Scope) 101 (Systems and Equipment) 102 (Compliance Approaches)	100 (Scope) 101 (Systems and Equipment) 102 (Compliance Approaches)	100 (Scope) 101 (Systems and Equipment) 102 (Compliance Approaches)	100 (Scope) 101 (Systems and Equipment) 102 (Compliance Approaches)
Definitions	200 (Definitions)	200 (Definitions)	200 (Definitions)	200 (Definitions)
Refrigerated Warehouse	900 (General) 901.1 (Refrigerated Warehouse) 913 (Process Piping)	N.A.	N.A.	901.4 (Refrigerated Warehouse) 913 (Process Piping)
Commercial Refrigeration	900 (General) 902.1 (Commercial Refrigeration) 913 (Process Piping)	N.A.	N.A.	902.4 (Commercial Refrigeration) 913 (Process Piping)
Enclosed Parking Garages	900 (General) 903.1 (Enclosed Parking Garages)	N.A.	N.A.	903.4 (Enclosed Parking Garages)
Process Boilers	900 (General) 904.1 (Process Boilers) 913 (Process Piping)	N.A.	N.A.	904.4 (Process Boilers) 913 (Process Piping)
Compressed Air	900 (General) 905.1 (Compressed Air)	N.A.	N.A.	905.4 (Compressed Air)

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[14] *Nonresidential* and *hotel/motel buildings* that contain *covered processes* may conform to the applicable requirements of both *occupancy types* listed in Tables 100.4-A and 100.4-B *[Table 100.0-A]*.

Elevator Ventilation and Lighting	900 (General) 906.1 (Elevators)	N.A.	N.A.	906.4 (Elevators)
Escalators and Moving Walkways	907.1 (Escalator and Moving Walkway)	N.A.	N.A.	907.4 (Escalator and Moving Walkway)
Controlled Environment Horticulture (CEH)	900 (General) 908.1 (CEH)	N.A.	N.A.	908.4 (CEH)
~~Steam Traps~~ Process Steam Systems	900 (General) 909.1 (~~Steam Traps~~ Process Steam Systems) 913 (Process Piping)	N.A.	N.A.	909.4 (~~Steam Traps~~ Process Steam Systems) 913 (Process Piping)
Computer Rooms	900 (General) 910.1 (Computer Rooms)	910.2	910.3	910.4 (Computer Rooms)
Commercial Kitchens	900 (General) 911.1 (Commercial Kitchen)	911.2	911.3	911.4 (Commercial Kitchen)
Laboratory/ Factory Exhaust Systems	900 (General)	912.2	912.3	912.4 (Laboratory and Factory)
Process Piping	913.1 (Process Piping)	N.A.	N.A.	913.4 (Process Piping)

SECTION 200 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 201 [Section 100.1(b)] **– Definitions - Recommends new or revised definitions for the following terms:**

CONDENSATE RETURN SYSTEM is a system designed to return steam condensate to a boiler plant for reuse that includes piping and may also include condensate collection tanks and mechanical pumping.

PROCESS STEAM SYSTEM is a steam system that has one or more connected process boilers and serves one or more process loads.

PROCESS, COVERED is a process that includes computer rooms, data centers, elevators, escalators and moving walkways, laboratories, enclosed parking garages, commercial kitchens, refrigerated warehouses, commercial refrigeration, compressed air systems, process boilers, process steam systems, process heating and cooling piping, and controlled environment horticultural spaces.

SUBCHAPTER 9 – PROCESS SYSTEMS AND EQUIPMENT

SECTION 909 – ~~STEAM TRAPS~~ PROCESS STEAM SYSTEMS (NEWLY CONSTRUCTED, ADDITIONS, ALTERATIONS)

909.1 Mandatory requirements (Newly Constructed, Additions, Alterations).

909.1.1 [Section 120.6(i)] **Mandatory requirements for steam traps.** Steam ~~traps in new industrial facilities~~ where the installed steam trap operating pressure, which is the steam pressure entering the steam trap during normal design operating conditions, is greater than 15 psig and the total combined connected boiler input rating is greater than 5 Million Btu/hr, shall meet the following requirements:

909.1.1.1 [Section 120.6(i)1] **Central steam trap fault detection and diagnostics monitoring.** Steam trap systems shall be equipped with a central steam trap monitoring system that:

A. Provides a status update of all steam trap fault detection sensors at no greater than 8-hour intervals.

B. Automatically displays an alarm that identifies which steam trap has a fault once the system has detected a fault.

909.1.1.2 [Section 120.6(i)2] **Steam trap fault detection.** Steam traps shall be equipped with *automatic* fault detection sensors that shall communicate their operational state to the central steam trap monitoring system as described in Section 909.1.1.1 [Section 120.6(i)1].

909.1.1.3 [Section 120.6(i)3] **Steam trap strainer installation.** Steam traps shall either:

A. Be equipped with an integral strainer and blow-off valve; or
B. Be installed downstream within 3 feet of a strainer and blow-off valve.

909.1.1.4 [Section 120.6(i)4] **Steam trap system acceptance**. Before an occupancy permit is granted for steam trap systems subject to Section 120.6(i), the equipment and systems shall be certified as meeting the Acceptance Requirement for Code Compliance, as specified by the Reference Nonresidential Appendix NA7.19. A Certificate of Acceptance shall be submitted to the enforcement agency that certifies that the equipment and systems meet the acceptance requirements specified in NA7.19.

Exception to Section 909.1.1: Steam traps where steam is diverted to a steam system of lower pressure for use when the steam trap fails open.

909.1.2 *[New section]* **Mandatory requirements for steam loads.**

909.1.2.1 *[New section]* **Condensate return.** The following requirements apply to all new, non-replacement process steam loads that use indirect-contact heat exchangers at new and existing facilities that meet the below conditions:

a. have one or more connected boilers with an input rating (capacity) of 10 MMBtu/h or greater, and
b. meet the criteria for linear distances corresponding to the applicable steam load size in Table 909.1.2.1-A.
    a. The linear distance shall be measured from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

TABLE 909.1.2.1-A *[New table]* STEAM LOAD CONDENSATE RETURN DISTANCE CODE TRIGGER CRITERIA

Steam Flow (lb/h)	**Linear Distance[15] (ft) Less Than**
<1,000	Exempt
≥1,000, <2,000	400
≥2,000, <3,000	600

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[15] Footnote to Table 909.1.2.1-A: Linear distance (sum of horizontal and vertical) from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

≥3,000, <4,000	800
≥4,000, <6,000	1,100
≥6,000	1,300

Qualifying *process steam loads* shall install a *condensate return system* to return all condensate, including condensate from new drip leg steam traps associated with the load, to the boiler plant for reuse.

All steam loads that do not qualify for Section 909.1.2.1 based on the criteria in Table 909.1.2.1-A shall include the following in the steam system construction documents:

- Linear distance (sum of horizontal and vertical) from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

Exception to Section 909.1.2.1: Process steam loads in hotel/motel buildings and nonresidential buildings with Group R occupancies.

909.4 [Section 141.1] **Additions and alterations to existing buildings.**

Covered processes in additions or alterations to existing buildings that will be nonresidential, hotel/motel, or multifamily occupancies shall comply with the applicable requirements of Section 400.5.1 [Section 110.2(a)] and Section 913 [Section 120.3].

909.4.1 Steam traps.

New steam traps added to support new, non-replacement, *process equipment* in existing industrial facilities where the installed steam trap operating pressure, which is the steam pressure entering the steam trap during normal design operating conditions, is greater than 15 psig and the total combined connected boiler input rating is greater than 5 million Btu/hr shall comply with the applicable requirements of Section 909**.1.1**, and the applicable requirements of Section 400.5.1 [Section 110.2(a)] and Section 913 [Section 120.3].

909.4.2 Steam loads.

New, non-replacement steam loads added to existing industrial facilities as part of an addition or alteration shall comply with the applicable requirements of Section 909.1.2 and Section 913 [Section 120.3].

3.6.4 Reference Appendices

There are no proposed updates to the Non-Residential Appendices.

3.6.5 Compliance Manuals

The Statewide CASE Team will provide CEC with recommended revisions to compliance manuals after the 45-Day Language is published.

3.6.6 ACM Reference Manual

The Statewide CASE Team proposes no changes to the ACM Reference Manual.

3.6.7 Compliance Forms

The NRCC-PRC-E and NRCI-PRC-E compliance forms would both need to be updated to reflect the proposed change. The Statewide CASE Team can support the CEC in implementing these updates if the proposed change is adopted. These potential updates would look as follows:

NRCC-PRC-E

Create a new section S Process Steam and update the following section's lettering. In the S Process Steam section:

- Create the following columns in the table for each new steam boiler load:
  - Which rated input capacity aligns with the process steam load (Btu/h)?
    - In the Virtual Compliance Assistant, add the following dropdown options:
      - Rated input capacity of one or more connected boilers: ≥ 10 MMBtu/h
  - Does the process steam load return all condensate to the boiler system for reuse?
    - If the site claims that the load does not trigger the requirement because of the linear distances in the code trigger table, provide the sheet number that supports the required calculation for the linear distance.
    - In Virtual Compliance Assistant, add the following dropdown options:
      - Yes
      - This doesn't apply because the boiler serving this process steam load has a rated capacity less than 10 MMBtu/h.
      - This doesn't apply because there is no condensate generated from the use of an indirect-contact heat exchanger.
      - This doesn't apply because the linear distance between the steam trap serving the load and the nearest condensate return tank or the deaerator is greater than the distance listed in the code trigger table for this size steam load.

NRCI-PRC-E

Create a new section S Process Steam in the NRCI-PRC-E and update the proceeding section's lettering. In the S Process Steam section table:

- Add the following to a new table for Process Steam for each new steam boiler load:

- Column for Condensate Return System Compliance. (P/F)
- Column for Condensate Return Pump:
  - Dropdown options to include:
    - Enter condensate pump(s) make and model number.
    - Not applicable because this load does not have a condensate return pump.
- Column for Condensate Return Labeled Piping:
  - Verify condensate return piping is installed and clearly labeled. (P/F)

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Appendix A: Assumptions for Cost-effectiveness Analysis

Calculations for Condensate Return Code Trigger Table Development

To determine the maximum qualifying lengths of code trigger table, the Statewide CASE Team analyzed the maximum cost-effective condensate return piping lengths separately for year-round and seasonal facilities. Because seasonal facilities operate fewer hours annually, they generally have longer payback periods. Therefore, the Statewide CASE Team used the maximum cost-effective piping lengths for seasonal facilities in the code trigger table to ensure the proposed requirements remain cost-effective across facilities with varying annual operating hours. The results of the simple payback calculations are shown in Table 43.

Table 43: Condensate Return Payback with Maximum Code Trigger Lengths

Boiler Capacity (MMBtu/h)	Trigger Length (ft)	Payback: Year-Round Boilers (years)	Payback: Seasonal Boilers (years)
10-15	400	6.3	8.5
15-25	600	6.8	9.2
25-50	600	6.1	8.3
50-100	1100	6.7	9.1
100-200	1300	6.3	8.5
200+	1300	3.5	4.8

Assumptions for Energy Savings Analysis

Flash Steam Recovery

For the flash steam recovery requirement, the baseline case is a steam system that does not recover any flash steam from boiler blowdown, and the proposed case is a steam system that recovers all of its flash steam from boiler blowdown and applies it to deaerator heating.

Savings calculation assumptions for both the baseline and proposed cases include the following:

a. Boiler operation (year-round boilers): 6,500 hours per year, based on a survey of 128 California steam-using sites sourced from the national IAC database

(Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

b. Boiler operation (seasonal boilers): 2,400 hours per year, based on a survey of 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).
c. Boiler load: constant 40 percent daily load for year-round boilers and constant 80 percent daily load for seasonal boilers, based on field experience and the assumption that seasonal boilers are operated at higher load factors to meet seasonal demand.
d. Combustion air temperature: 75°F, based on outdoor air temperatures in California.
e. Combustion efficiency: 80.5 percent, based on field data from 10 sites.
f. Shell losses: 1.0 percent, based on industry standard rule of thumb.
g. Boiler efficiency: 79.5 percent, equivalent to the combustion efficiency minus shell losses.
h. Feedwater temperature (deaerator operating temperature): 227°F
i. Condensate temperature: 200°F
j. Make-up water temperature: 65°F
k. Condensate conductivity: 20 micro-mhos (µ℧), based on sample boiler log data.
l. Make-up water conductivity: 440 (µ℧), based on sample boiler log data.
m. Percent of steam loads with returned condensate: 30%
n. Boiler steam pressure: 100 psig
o. Flash steam pressure: 8 psig
p. Deaerator pressure: 5 psig, based on field experience.
q. Enthalpy values calculated from steam tables.

Savings calculation assumptions and outputs for the baseline case include the following:

- Flash steam recovery: 0 percent recovery from blowdown

Savings calculation assumptions and outputs for the proposed measure case include the following:

- Flash steam recovery: 100 percent recovery from blowdown

The estimated recovered flash steam mass flow for each boiler category is shown in Table 44 below.

Table 44: Estimated Recovered Flash Steam Mass Flow by Boiler Capacity

Boiler Category	Recovered Flash Steam Mass Flow (lbm/h)
Year-Round 10-15 MMBtu/h	49
Year-Round 15-25 MMBtu/h	75
Year-Round 25-50 MMBtu/h	129
Year-Round 50-100 MMBtu/h	279
Year-Round 100-200 MMBtu/h	561
Year-Round 200+ MMBtu/h	2,899
Seasonal 10-15 MMBtu/h	98
Seasonal 15-25 MMBtu/h	149
Seasonal 25-50 MMBtu/h	259
Seasonal 50-100 MMBtu/h	557
Seasonal 100-200 MMBtu/h	1,122
Seasonal 200+ MMBtu/h	5,799

Condensate Return

For the condensate return requirement, the baseline case is a steam system that reuses 30 percent of its condensate, and the proposed case is a steam system that reuses 75 percent of its total steam flow returned as condensate. The 30 percent condensate return in the baseline case represents the naturally occurring market adoption of condensate return.

Savings calculation assumptions for both the baseline and proposed cases include the following:

a. Boiler operation (year-round boilers): 6,500 hours per year, based on a survey of from 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).
b. Boiler operation (seasonal boilers): 2,400 hours per year, based on a survey of 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).
c. Boiler load: 40 percent load for year-round boilers and 80 percent load for seasonal boilers for energy savings analysis. The Statewide CASE Team used 80 percent load for both seasonal and year-round boilers to calculate cost due to common practice of sizing for full load.
d. Combustion air temperature: 75°F, based on outdoor air temperatures in California.

e. Combustion efficiency: 80.5 percent, based on field data from 10 sites.
f. Shell losses: 1.0 percent, based on industry standard rule of thumb.
g. Boiler efficiency: 79.5 percent, equivalent to the combustion efficiency minus shell losses.
h. Feedwater temperature: 226°F, based on a deaerator pressure of 5psig.
i. Condensate temperature: 200°F, based on data from industrial steam sites.
j. Make-up water temperature: 65°F, estimated based on California water supply temperatures.
k. Condensate conductivity = 20 (μ℧), based on field data from two industrial sites from prior work with Cascade Energy.
l. Make-up water conductivity = 440 (μ℧), based on field data from two industrial sites from prior work with Cascade Energy.
m. Feedwater conductivity = 345 (μ℧), based on based on field data from two industrial sites from prior work with Cascade Energy.
n. Steam pressure: 100 psig, average industry steam header pressure.
o. Enthalpy values calculated from steam tables.

Savings calculation assumptions and outputs for the baseline case include the following:

- Condensate return: 30 percent, a conservative estimate based on field experience. This accounts for naturally occurring market adoption of condensate return statewide.

Savings calculation assumptions and outputs for the proposed measure case include the following:

- Condensate return: 75 percent, an estimate of the total steam flow as viable condensate for return and reuse at the average site based on field experience and stakeholder input. The remaining 25 percent includes contaminated condensate and deaerator steam supply.

The energy impacts of flash steam recovery would not vary due to individual equipment makes or models, but they will vary based on the steam system design and operating characteristics (e.g., operating pressure, relative load size, and load profile).

Energy savings do not vary by climate zone for either proposed measure. The Statewide CASE Team applied the climate-zone-specific LSC hourly factors when calculating energy cost impacts for both measures.

The estimated average condensate mass flow increase for each boiler category is shown in Table 45 below.

Table 45: Estimated Incremental Condensate Mass Flow

Boiler Category	Incremental Condensate Mass Flow (lbm/h)
Year-Round 10-15 MMBtu/h	1,463
Year-Round 15-25 MMBtu/h	2,377
Year-Round 25-50 MMBtu/h	3,984
Year-Round 50-100 MMBtu/h	8,643
Year-Round 100-200 MMBtu/h	17,452
Year-Round 200+ MMBtu/h	90,396
Seasonal 10-15 MMBtu/h	2,901
Seasonal 15-25 MMBtu/h	4,712
Seasonal 25-50 MMBtu/h	7,897
Seasonal 50-100 MMBtu/h	17,134
Seasonal 100-200 MMBtu/h	34,598
Seasonal 200+ MMBtu/h	179,204

Energy Savings Methodology

Prototype Development – Flash Steam Recovery and Condensate Return

The Statewide CASE Team analyzed energy savings and cost effectiveness in six boiler capacity ranges to account for savings and cost differences for boilers with different capacities. Table 46 shows the boiler capacity bin ranges and the average boiler capacity for each bin, which were used to estimate savings and perform cost-effectiveness calculations. Data on the capacity of installed boilers in California came from the statewide boiler inventory of local air district boiler permits developed as part of the Code Readiness program (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025). Boilers not subject to Title 24 jurisdiction were removed prior to determining the average capacity within each bin.

Table 46: Process Boiler Capacity Bins

Boiler Capacity Bin	Average Boiler Capacity Used for Calculations
10-15 MMBtu/h	12 MMBtu/h
15-25 MMBtu/h	19 MMBtu/h
25-50 MMBtu/h	33 MMBtu/h
50-100 MMBtu/h	71 MMBtu/h
100-200 MMBtu/h	143 MMBtu/h
200+ MMBtu/h	739 MMBtu/h

For both measures, boilers that operate infrequently throughout the year due to seasonal loads will experience lower savings. Due to this variance, the Statewide CASE Team also developed prototypes and calculated annual energy savings and cost effectiveness for boilers with seasonal loads separately from the more typical annual loads. To calculate statewide capacity, seasonal boilers were defined as all boilers in canneries. Boilers used in all other industries were assumed to be year-round boilers.

The review finds no anticipated differences between new process boilers installed during new construction, additions, or alterations of a building, so the same prototypes were used for all three.

Existing Title 24, Part 6 requirements already cover process boilers and apply to new construction, additions, and alterations, so the Standard Design (i.e., baseline case) is compliant with the 2025 Title 24 requirements and representative of the non-compliant market. The Standard Design informs the baseline combustion efficiency estimate used in savings calculations. These requirements include combustion air positive shut-off for all process boilers with an input capacity of 2.5 MMBtu/h and above, variable speed drive for process boiler combustion air fans with motors 10 horsepower and greater, and stack oxygen concentrations at less than or equal to 3.0 percent by volume on a dry basis over firing rates of 20 to 100 percent for process boilers with an input capacity greater than 5.0 MMBtu/h. The 2028 CASE Methodology Report provides details on estimating energy savings for prototypical buildings and units.

Energy Savings Calculations

Flash Steam Recovery

The Proposed Design (i.e., measure case) was identical to the Standard Design in all respects except for the revisions that represent the proposed code changes. Specifically, the proposed conditions assume installation of blowdown flash steam recovery equipment.

Savings result from reducing the amount of flash steam that is vented to the atmosphere. The key equations used in a custom Microsoft Excel model developed for this savings analysis follow.

1. Fraction of condensate that vaporizes into flash steam:

$$x = \frac{h_{blowdown} - h_{f,LP}}{h_{fg,LP}}$$

where

$x = fraction\ of\ blowdown\ mass\ flow\ that\ flashes\ into\ steam$

$h_{blowdown} = enthalpy\ of\ boiler\ water h_{f,LP}$
$= enthalpy\ of\ saturated\ liquid\ at\ flash\ steam\ (lower)\ pressure$

$h_{fg,LP} = enthalpy\ of\ vaporization\ at\ flash\ steam\ (lower)\ pressure$

2. Flash steam mass flow:

$$\dot{m}_{flash\ steam} = \dot{m}_{blowdown} \cdot x$$

where

$\dot{m}_{blowdown} = \text{mass flow of boiler blowdown}$

3. Live boiler steam energy saved from flash steam recovery:

$\dot{E}_{recovered} = \dot{m}_{flash\ steam} \cdot (h_{f,LP} - h_{makeup})$ where

$\dot{E}_{recovered} = rate\ of\ recovered\ energy$

$\dot{m}_{flash\ steam} = mass\ flow\ of\ flash\ steam$

$h_{makeup} = enthalpy\ of\ makeup\ water$

4. Fuel saved from flash steam recovery:

$$\dot{E}_{fuel\ savings} = \frac{\dot{E}_{recovered}}{\eta_{boiler}}$$

where

$\dot{E}_{fuel\ savings} = boiler\ fuel\ savings$

$\eta_{boiler} = boiler\ system\ efficiency$

Consider a 50 MMBtu/h boiler operating at 100 psig with 1,800 lbm/h of blowdown flow. Assume flash steam is recovered at 8 psig and that makeup water is supplied at 65°F. All enthalpy values are taken for an elevation of sea level and sourced from the National Institute of Standards and Technology (NIST) Chemistry WebBook.

Fraction of blowdown that vaporizes into flash steam

$$x = \frac{h_{blowdown} - h_{f,LP}}{h_{fg,LP}}$$

where

$$h_{blowdown} = 309.2 \frac{Btu}{lbm} \; saturated\ liquid\ enthalpy\ of\ boiler\ water\ at\ 100\ psig\ (114.7\ psia)$$

$$h_{f,LP} = 203.3 \frac{Btu}{lbm} \; saturated\ liquid\ enthalpy\ at\ flash\ vessel\ pressure\ of\ 8\ psig\ (22.7\ psia)$$

$$h_{fg,LP} = 956.2 \frac{Btu}{lbm} \; latent\ enthalpy\ at\ flash\ vessel\ pressure\ of\ 8\ psig\ (22.7\ psia)$$

Hence

$$x = \frac{309.2\ Btu/lbm - 203.3\ Btu/lbm}{956.2\ Btu/lbm}$$

$$x = 11.1\%$$

Flash steam mass flow

$$\dot{m}_{flash\ steam} = \dot{m}_{blowdown} \cdot x$$

$$\dot{m}_{flash\ steam} = 1{,}800 \frac{lbm}{h} \cdot 11.1\%$$

$$\dot{m}_{flash\ steam} = 199.8\ lbm/h$$

Steam energy recovered

$$\dot{E}_{recovered} = \dot{m}_{flash\ steam} \cdot (h_{flash\ steam} - h_{makeup})$$

where

$$h_{makeup} = 33.0 \frac{Btu}{lbm}, enthalpy\ of\ makeup\ water\ at\ 65°F$$

$$h_{flash\ steam} = 1{,}159.4 \frac{Btu}{lbm} saturated\ vapor\ enthalpy\ at\ flash\ steam\ pressure$$

Hence

$$\dot{\mathrm{E}}_{recovered} = 199.8\,\frac{lbm}{h}\cdot(1{,}159.4\frac{Btu}{lbm} - 33.0\frac{Btu}{lbm})$$

$$\dot{\mathrm{E}}_{recovered} = 225{,}055\;Btu/h$$

Boiler fuel savings

$$\dot{\mathrm{E}}_{fuel\ savings} = \frac{\dot{\mathrm{E}}_{recovered}}{\eta_{boiler}}$$

where

$\dot{\mathrm{E}}_{fuel\ savings} = boiler\ fuel\ savings, calculated\ above$

$\eta_{boiler} = boiler\ system\ efficiency, 0.795, assumed$

Hence

$$\dot{\mathrm{E}}_{fuel\ savings} = \frac{225{,}055\;Btu/h}{0.795}$$

$$\dot{\mathrm{E}}_{fuel\ savings} = 283{,}088\;Btu/h$$

Condensate Return

The Proposed Design (i.e., measure case) was identical to the Standard Design in all respects except for the revisions that represent the proposed code changes. Specifically, the proposed conditions assume installation of a condensate return system.

Energy savings from this measure were calculated in two components:

1. Deaerator preheating savings: Replacing cold make-up water with warm or hot returned condensate reduces the energy required to heat the deaerator.
2. Blowdown reduction: Replacing make-up water containing dissolved solids with condensate (which is effectively distilled water) reduces blowdown. Reducing blowdown reduces energy losses by reducing the total amount of feedwater that needs to be heated.

The estimated energy savings were based on the temperature difference between condensate and make-up water:

$$Energy\ Savings\left(\frac{Btu}{hr}\right) = \left(\dot{m}_{condp} - \dot{m}_{condb}\right) * \ c_p * (T_{con} - T_{mw})$$

where

$\dot{m}_{condp} = proposed\ condensate\ flow\ (\frac{lbm}{hr})$

$\dot{m}_{condb} = baseline\ condensate\ flow\ (\frac{lbm}{hr})$

$$T_{con} = temperature\ of\ condensate\ (°F)$$

$$T_{mw} = temperature\ of\ makeup\ water (°F)$$

$$c_p = constant - pressure\ specific\ heat\ capacity\ of\ water$$

Temperature losses due to condensate pipe length are accounted for in energy savings calculations. Insulation of condensate return pipes is already required by Title 24 Part 6.

The following equation was used to calculate energy savings due to decreased blowdown:

$$Blowdown\ Energy\ \left(\frac{Btu}{hr}\right) = (\dot{m}_{bdnb} - \dot{m}_{bdnp}) * (h_{bw} - h_{mw})$$

where

$$\dot{m}_{bdnb} = baseline\ blowdown\ flow\ rate\ in\ (\frac{lbm}{hr})$$

$$\dot{m}_{bdnp} = proposed\ blowdown\ flow\ rate\ in\ (\frac{lbm}{hr})$$

$$h_{bw} = specific\ enthalpy\ of\ boiler\ water\ (\frac{Btu}{lbm})$$

$$h_{mw} = specific\ enthalpy\ of\ makeup\ water\ (\frac{Btu}{lbm})$$

$$\dot{m}_{bdnb} = \frac{\dot{m}_{steam}}{COC - 1}$$

$$COC = cycles\ of\ concentration = \frac{C_b}{C_{fw}}$$

$$C_b = average\ conductivity\ of\ boiler\ water$$

$$C_{fw} = average\ conductivity\ of\ feedwater$$

Key Assumptions for Incremental Costs

Flash Steam Recovery First Costs

Table 47 below shows the breakdown of the flash steam recovery measure first costs for a boiler with an input capacity of 32.6 MMBtu/h. The Statewide CASE Team calculated first costs using a boiler load factor of 80 percent for both year-round and seasonal boilers, as equipment is often sized for greater loads than actual operating loads.

Table 47: Flash Steam Recovery Incremental Cost Breakdown

Item	Cost Explanation	Item Cost or Quantity
Flash vessels	Linear extrapolation by load size of costs from a vendor stakeholder conversation in October 2024	$5,000
Pipe diameter	2-inch diameter calculated by flash steam velocity calculation for active steam load; price obtained from 2025 Q2 RSMeans data	$51.78/linear foot (LF)
Total schedule 40 pipe length (labor & materials)	Estimated 100 feet average linear length between deaerator and blowdown flash vessel	$5,178
Pipe insulation w/ all service jacket (labor & materials)	2025 RSMeans data, fiberglass insulation with all service jacket: $45.36/LF	$4,536
Additional valves, strainers, and fittings (materials only)	Estimated to be 20 percent of total piping cost per engineering judgement	$1,036
Additional install labor	Estimated to be 20 percent of total project cost, including oversight, coordination, startup, and commissioning per engineering judgement	$3,150
Total Measure Cost		$18,900

Flash Steam Recovery Maintenance Costs

Table 48 below shows the breakdown of the discounted flash steam recovery measure maintenance costs for each boiler capacity bin. The costs are equivalent for year-round and seasonal boiler capacity. Maintenance costs include ten percent of the initial piping insulation costs, incurred twice, once in year 10 and once in year 20.

Table 48: Flash Steam Recovery Maintenance Costs by Boiler Capacity

Boiler Capacity (MMBtu/h)	Total Discounted 30-Year Maintenance Costs
10-15	$5,887
15-25	$5,878
25-50	$6,723
50-100	$7,246
100-200	$8,150
200+	$13,431

Condensate Return First Costs

The Statewide CASE Team calculated first costs using a boiler load factor of 80 percent for both year-round and seasonal boilers, as equipment is often sized for greater loads than actual operating loads. The Statewide CASE Team calculated steam loads and the quantity of returned condensate for the average boiler capacity within each boiler capacity bin, and adjusted assumptions around pipe length, diameter, and number of required fittings, elbows, tanks, valves, and pumps based on the size of the steam load. The Statewide CASE Team assigned a specific number of steam loads at each boiler capacity, as outlined in Table 49. The number of steam loads at the boiler informs the pipe length, pipe diameter, and number of pumps installed to comply with the proposed measure.

Table 49: Steam Load Assumptions by Boiler Capacity

Boiler Capacity (MMBtu/h)	Number of Steam Loads	Pipe Length (ft)	Pipe Diameter (inches)
10-15	2	300	1.5
15-25	2	450	2.0
25-50	3	450	2.0
50-100	4	825	2.0
100-200	5	975	2.5
200+	12	975	3.5

When calculating the incremental measure costs, the Statewide CASE Team estimated that pipe lengths equivalent to 75 percent of the maximum length from the code trigger table represent a conservative average of installed piping length based on engineering judgement.

Table 50 shows the breakdown of the condensate return measure first costs for a boiler with an input capacity of 12 MMBtu/h.

Table 50: Condensate Return Incremental First Cost Breakdown

Item	Cost Explanation	Item Cost or Quantity
Pipe Diameter	Calculated at Pressure drop < 0.1 psig/100 LF for specific steam load (conservative estimate)	1.5 inches
Pipe Length	75% of maximum length (400ft) in code trigger table for a condensate load of 3gpm for an input capacity of 12MMBtu/h. Estimate of two loads for this steam load size.	300 feet per load
Pipe Cost	RSMeans data, 2025 Q2 for Vallejo, Calif.	$53.68/LF
Fittings, Elbows, Tanks and Valves	Estimated to be equivalent to piping costs. Tank costs are estimated at 50% of the total cost of fittings, elbows, tanks, and valves.	$53.68/LF
Total Labor Costs	Estimated to be 1.5 times the piping cost, based on costs from a recent Cascade Energy project in California	$80.52
Pump Cost	Linear extrapolation of RSMeans data, 2025 Q2 for Vallejo, Calif. Estimate of two pumps based on steam load size.	$10,001 per pump
Insulation Costs	RSMeans, fiberglass insulation with all service jacket for 2-inch insulation (1.5-inch pipe at 200°F	$20.89/LF
Total Cost per LF	Cost per LF for 300 feet	$238.77
Total Project Cost per Load	Cost for one load at 75% of max trigger table length (300 LF)	$71,630
Total Project Cost	Cost for two loads at 300 linear feet per load determined by steam load size	$143,260

Condensate Return Maintenance Costs

Table 51 below shows the breakdown of the discounted condensate return incremental maintenance costs for each prototype. The costs are equivalent for year-round and seasonal boiler capacity. Maintenance costs include pump replacement in year 10 and year 20, condensate return tank replacement in year 20, and replacement of ten percent of the piping insulation both in year 10 and in year 20.

Table 51: Condensate Return Maintenance Costs by Boiler Capacity

Boiler Capacity (MMBtu/h)	Total Discounted 30-Year Maintenance Costs
10-15	$36,094
15-25	$45,337
25-50	$67,075
50-100	$120,193
100-200	$199,969
200+	$564,597

Appendix B: Purpose and Necessity of Proposed Code Changes

Introduction

The sections below provide the purpose and necessity of proposed changes to Title 24, Part 1; Title 24, Part 6; and the reference appendices. This section intends to provide the CEC with the information needed for the Initial Statement of Reasons.

Section 2.6 provides the marked-up code language for reference.

Flash Steam Recovery

Purpose and Necessity of Changes to Title 24, Part 1

No changes are proposed to Title 24, Part 1.

Purpose and Necessity of Changes to Title 24, Part 6

Section: 100.4

Purpose: The purpose of this change is to update the section name in Table 100.4-B to align with the newly proposed Process Steam Systems section.

Necessity: This change maintains section name consistency across the code.

Section: 200.1

Purpose: The purpose of this change is to aid in the interpretation and implementation of new requirements for process boilers flash steam reduction in Title 24, Part 6, Section 904.1 by adding new definitions.

Necessity: This change adds definitions for Flash Steam and Pressurized Condensate Return. These definitions ensure clarity of the proposed condensate return requirements.

Section: 904.1.4

Purpose: The purpose of these changes is to create a requirement to recover flash steam from blowdown to the deaerator or another heating load. Flash steam contains thermal energy that, if not recovered and used for other purposes, is wasted. Reducing or repurposing flash steam will therefore save energy.

Necessity: These proposed changes are intended to reduce the energy consumption in steam systems. These adjustments align with the mandated cost-effective building design standards outlined in the California Public Resources Code, specifically Sections 25213 and 25402.

Purpose and Necessity of Changes to the Reference Appendices

There are no required updates to the reference appendices as a result of this measure.

Condensate Return

Purpose and Necessity of Changes to Title 24, Part 1

No changes are proposed to Title 24, Part 1.

Purpose and Necessity of Changes to Title 24, Part 6

Section: 200.1

Purpose: The purpose of this change is to aid in the interpretation and implementation of new requirements for process steam system condensate return in Title 24, Part 6, Section 909.1 by adding new definitions and amending an existing definition.

Necessity: This change adds definitions for Condensate Return System and Process Steam System and amends the definition of a Covered Process. These definitions provide necessary clarity for the proposed additions to Title 24, Part 6, Section 909.1 that require the use of condensate return for process steam loads.

Section: 909.1.2

Purpose: The purpose of these changes is to require newly added steam loads to return viable condensate, provided that the new load is within a maximum linear distance from a condensate return tank or deaerator. Condensate contains thermal energy which, if not returned to a boiler or condensate sink, would otherwise be wasted. Use of condensate return systems recovers this energy.

Necessity: These changes are intended to reduce energy consumption in the process steam system . These adjustments align with the mandated cost-effective building design standards outlined in the California Public Resources Code, specifically Sections 25213 and 25402.

Purpose and Necessity of Changes to the Reference Appendices

There are no proposed changes to the reference appendices.

Appendix C: Assumptions for Statewide Savings Estimates

Flash Steam Recovery

The Statewide CASE Team took the following steps to determine statewide savings from the proposed flash steam recovery measure.

To estimate statewide boiler capacities and counts by boiler capacity bins, the Statewide CASE Team leveraged statewide boiler inventory data developed as part of a Code Readiness project. This inventory is a nearly complete statewide boiler inventory that has over 9,000 equipment entries from local air quality management districts, which were collected and preprocessed by the Code Readiness project team in 2023 and 2024 (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

The Statewide CASE Team refined the statewide capacity for each capacity bin to account for Title 24 purview and requirement exceptions, making the following changes:

- Removed boilers with input capacities under 10 MMBtu/h and any units that were indicated to be hot water boilers or hot water heaters in the permit data.
- Removed oilfield and utility boilers, which are not in buildings and not subject to Title 24, Part 6 requirements.
- Removed 5 percent of remaining boiler capacity to account for boilers without a pressurized deaerator, boilers with pressurized condensate return, and boilers with a linear distance from the boiler to the serving deaerator greater than or equal to 100 feet, based on analysis of steam system operating pressures from IAC boiler audits;
- Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.
  - The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes were made represents the Existing Boilers Stock. Boilers at or above 10 MMBtu/h in the healthcare, education, non-cannery food, refinery, lumber, and ‘all other’ sectors were included in the statewide capacity totals.

To estimate the capacity of new process boilers installed annually from new construction and additions, the Statewide CASE Team calculated two IPGRs for boilers in California: one for annual boilers and one for seasonal boilers.

The Statewide CASE Team analyzed both national and state data to develop an IPGR for California. The IPGR from the 2022 Steam Trap Monitoring CASE Report was calculated using an average of the 10-year and 30-year compound annual growth rate (CAGR) of INDPRO, the national Federal Industrial Production Index (Johnson, Heinrichs, & Coakley, 2020). However, the Statewide CASE Team determined that national trends would not provide an accurate representation of the California industrial production market. While California is the largest contributor to the U.S. manufacturing industry in terms of output and employment, it accounts for 14.5 percent of U.S. manufacturing output (Profozich, 2022). A study performed by Beacon Economics for the California Manufacturing Network confirmed that California’s manufacturing sector has grown at a faster rate compared with that of the US (Economics, n.d.).

To more accurately estimate California’s IPGR, the Statewide CASE Team met with Beacon Economics to discuss the availability of California-specific data on industrial production growth and the differences between California's manufacturing sector and the U.S. manufacturing sector as a whole. Beacon Economics provided a 2025 study demonstrating that California's manufacturing growth was not only faster than the rest of the United States, but California's manufacturing is also more productive (Beacon Economics, 2025). The Statewide CASE Team investigated California real Gross Domestic Product (GDP) data from the U.S. Bureau of Economic Analysis (BEA) and California Federal Reserve Bank of St. Louis’ Federal Reserve Economic Data (FRED) for industries classified as manufacturing per 2017 NAICS (U.S. Bureau of Economic Analysis, 2025; FRED, 2025).

The Statewide CASE Team calculated the average of the 7-year CAGR and 10-year CAGR from both sources through 2024. The California real GDP manufacturing growth rate from BEA and FRED was similar at 2.25 percent and 2.74 percent, respectively. The BEA data provided a more conservative growth rate and were selected for California IPGR calculations.

To further tailor this data to the proposed flash steam recovery measure, the Statewide CASE Team applied weights based on the proportion of boiler capacity in each of the main industry subsectors (i.e., food and beverage manufacturing, wood manufacturing, and total other manufacturing which is defined as all other manufacturing that was not food and beverage, wood, lumber, petroleum/refining, or other subsectors that burn byproduct waste), calculated from the statewide boiler inventory based on AQMD data to subsector-specific California real GDP BEA data. Boiler capacity from canneries was excluded from the weighted average for year-round boilers. The calculated weighted average IPGR for year-round boilers was 1.65 percent.

The growth rate for the seasonal facilities is best represented by the Food and Beverage Manufacturing IPGR of 0.46 percent, which was calculated from BEA real GDP data in 2017 chained dollars.

Statewide savings estimates were calculated using an IPGR of 1.65 percent for year-round boilers and 0.46 percent for seasonal boilers. The annual new construction and additions forecast is equivalent to the Existing Boiler Stock multiplied by the IPGR.

To estimate the capacity of new process boilers installed annually from alterations or replacements, the Statewide CASE Team calculated the replacement rate for boilers and applied it to Existing Boiler Stock. Boiler lifetimes range widely, with most estimates in the 25- to 40-year range (Van Wortswinkel & Nijs, 2010). The boiler replacement rate is based on a 30-year boiler lifetime, which means that 3.3 percent of the Existing Boiler Stock is replaced each year. The alteration forecast is therefore equivalent to the Existing Boiler Stock multiplied by 3.3 percent.

The Statewide CASE Team then multiplied the per-unit measure savings by the annual new construction and additions forecast and by the alterations forecast to obtain statewide savings, not accounting for natural market adoption.

The final statewide savings and cost estimates take the current market share rate into account. The Statewide CASE Team estimated current market adoption of flash steam recovery at 10 percent of newly added qualifying boiler capacity, based on interviews with boiler manufacturers and vendors and data on analysis of IAC audit data from 64 boilers in 32 steam-using industrial plants from 2010 to 2022.

The Statewide CASE Team applied this market share percentage to the statewide savings for the flash steam recovery measure to arrive at the final statewide savings estimate.

The energy impacts of the proposed code change do not vary by climate zone. The measure is not climate-dependent because the impact of the outdoor air temperature on the boiler's operation is minimal and does not materially impact estimated measure savings. Since savings do not vary by climate zone, the Statewide CASE Team used the statewide LSC hourly factors when calculating energy and LSC impacts.

Table 52 shows the percentages of statewide boiler capacity that would be impacted by the proposed code changes in 2029 among boilers with input capacities over 10 MMBtu/h. These percentages take into account the industries not impacted by Title 24, Part 6, and the exceptions for each measure, but not the estimated market share of compliance with the requirement. The Statewide CASE Team developed these estimates using the methods described in this section. No differences in affected boiler capacity are found by climate zone.

Table 52: Percentage of Statewide Boiler Capacity Impacted by Proposed Code Change in 2029, by Prototype – Flash Steam Recovery

Boiler Category	New Construction and Additions Impacted (Percent Capacity)	Existing Boiler Capacity (Alterations) Impacted (Percent Capacity)
Year-Round Boiler 10-15 MMBtu/h	84.9%	2.8%
Year-Round Boiler 15-25 MMBtu/h	83.8%	2.8%
Year-Round Boiler 25-50 MMBtu/h	82.8%	2.8%
Year-Round Boiler 50-100 MMBtu/h	41.7%	1.4%
Year-Round Boiler 100-200 MMBtu/h	85.5%	2.8%
Year-Round Boiler 200+ MMBtu/h	25.1%	0.8%
Seasonal Boiler 10-15 MMBtu/h	85.5%	0.3%
Seasonal Boiler 15-25 MMBtu/h	85.5%	0.3%
Seasonal Boiler 25-50 MMBtu/h	85.5%	0.3%
Seasonal Boiler 50-100 MMBtu/h	85.5%	0.3%
Seasonal Boiler 100-200 MMBtu/h	85.5%	0.3%
Seasonal Boiler 200+ MMBtu/h	85.5%	0.3%

Table 52, Table 53, and Table 54 present the projected new and existing process boiler capacity that the proposed code changes would respectively impact in 2029. The Statewide CASE Team developed these estimates using the methods described earlier in this section. The 2028 CASE Methodology Report includes additional information about the methodology and assumptions used to calculate statewide energy impacts.

Table 53: Estimated New Process Boiler Capacity Impacted by Proposed Flash Steam Recovery Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.2	2.0	11.2	5.2	1.4	8.8	5.8	12.4	15.3	11.9	2.5	19.0	13.5	2.2	1.9	0.8	114.1
Year-Round 15-25 MMBtu/h	0.0	1.7	10.2	4.6	1.8	10.3	3.5	14.6	18.0	12.5	2.1	22.8	22.6	3.9	3.1	1.4	133.3
Year-Round 25-50 MMBtu/h	0.9	2.2	13.4	6.7	2.8	12.8	4.6	13.1	19.3	11.9	2.7	34.8	28.8	4.5	1.8	1.8	162.1
Year-Round 50-100 MMBtu/h	0.0	1.4	22.0	3.8	1.0	2.0	2.0	3.3	3.7	3.4	1.4	119.3	177.4	3.9	1.5	0.7	346.8
Year-Round 100-200 MMBtu/h	0.0	2.7	14.9	7.0	0.0	3.9	0.0	5.5	7.2	4.1	2.7	44.1	36.4	9.0	2.5	2.0	142.0
Year-Round 200+ MMBtu/h	3.8	2.4	11.6	6.3	0.0	18.3	0.0	36.6	41.8	27.4	25.6	11.5	3.6	13.4	7.8	3.3	213.5
Seasonal 10-15 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Seasonal 15-25 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Seasonal 25-50 MMBtu/h	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.2	0.2	0.0	0.0	0.0	0.9
Seasonal 50-100 MMBtu/h	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	1.9	2.8	0.1	0.0	0.0	5.5
Seasonal 100-200 MMBtu/h	0.0	0.3	1.7	0.8	0.0	0.4	0.0	0.6	0.8	0.5	0.3	5.1	4.2	1.0	0.3	0.2	16.5
Seasonal 200+ MMBtu/h	0.4	0.2	1.1	0.6	0.0	1.8	0.0	3.6	4.1	2.7	2.5	1.1	0.4	1.3	0.8	0.3	20.8
TOTAL	**5.3**	**13.0**	**86.7**	**35.1**	**7.1**	**58.5**	**16.0**	**89.8**	**110.5**	**74.6**	**39.9**	**259.9**	**289.9**	**39.3**	**19.8**	**10.5**	**1,156.0**

Table 54: Estimated Existing Process Boiler Capacity Impacted by Proposed Flash Steam Recovery Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.3	4.0	22.7	10.4	2.9	17.8	11.8	24.9	30.9	24.0	5.0	38.2	27.2	4.4	3.8	1.6	229.9
Year-Round 15-25 MMBtu/h	0.0	3.5	20.6	9.4	3.7	20.7	7.0	29.5	36.2	25.3	4.2	45.9	45.6	7.9	6.3	2.8	268.6
Year-Round 25-50 MMBtu/h	1.9	4.5	27.0	13.5	5.7	25.8	9.3	26.4	38.9	24.0	5.4	70.2	58.0	9.0	3.6	3.6	326.8
Year-Round 50-100 MMBtu/h	0.0	2.7	44.3	7.7	2.0	4.1	4.1	6.6	7.5	6.8	2.9	240.4	357.5	7.8	3.1	1.4	698.9
Year-Round 100-200 MMBtu/h	0.0	5.4	30.0	14.0	0.0	7.8	0.0	11.1	14.6	8.3	5.5	89.0	73.3	18.2	5.1	4.1	286.2
Year-Round 200+ MMBtu/h	7.7	4.9	23.4	12.6	0.0	36.9	0.0	73.7	84.3	55.3	51.6	23.2	7.2	27.0	15.7	6.6	430.2
Seasonal 10-15 MMBtu/h	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.1	0.0	0.2	0.1	0.0	0.0	0.0	1.1
Seasonal 15-25 MMBtu/h	0.0	0.0	0.2	0.1	0.0	0.2	0.1	0.2	0.3	0.2	0.0	0.3	0.3	0.1	0.0	0.0	2.0
Seasonal 25-50 MMBtu/h	0.0	0.1	0.6	0.3	0.1	0.5	0.2	0.5	0.8	0.5	0.1	1.4	1.2	0.2	0.1	0.1	6.7
Seasonal 50-100 MMBtu/h	0.0	0.2	2.5	0.4	0.1	0.2	0.2	0.4	0.4	0.4	0.2	13.7	20.4	0.4	0.2	0.1	40.0
Seasonal 100-200 MMBtu/h	0.0	2.3	12.5	5.9	0.0	3.3	0.0	4.6	6.1	3.5	2.3	37.1	30.6	7.6	2.1	1.7	119.5
Seasonal 200+ MMBtu/h	2.7	1.7	8.2	4.4	0.0	12.9	0.0	25.8	29.5	19.4	18.1	8.1	2.5	9.5	5.5	2.3	150.8
TOTAL	**12.7**	**29.3**	**192.1**	**78.7**	**14.5**	**130.3**	**32.7**	**203.9**	**249.7**	**167.6**	**95.3**	**567.9**	**624.1**	**92.0**	**45.7**	**24.3**	**2,560.8**

Condensate Return

To determine statewide savings from the proposed condensate return measure, the Statewide CASE Team first assumed that statewide boiler capacities are a fair representation of steam system capacity. To estimate statewide boiler capacities and counts by boiler capacity bins, the Statewide CASE Team leveraged statewide boiler inventory data developed as part of a Code Readiness project. This inventory is a nearly complete statewide boiler inventory with over 9,000 equipment entries from local air quality management districts, which were collected and preprocessed by the Code Readiness project team in 2023 and 2024 (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

The Statewide CASE Team made the following changes to the statewide capacity in each capacity bin to account for Title 24 purview and requirement qualification:

- Removed boilers with input capacities under 10 MMBtu/h;
- Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements;
- Removed 10 percent of remaining boiler capacity to account for steam loads that would not qualify for the requirement via the code trigger table for the condensate return requirement;
- Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.
    - The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes were made represents the existing boiler stock, which is a proxy for the existing capacity of statewide qualifying steam loads. Boiler capacity at or above 10 MMBtu/h in the healthcare, education, lumber, and refinery sectors were included in the statewide capacity totals.

To estimate the capacity of new steam loads installed annually, the Statewide CASE Team calculated four IPGRs for California: year-round new construction, year-round additions and alterations, seasonal new construction, and seasonal additions and alterations. The Statewide CASE Team analyzed both national and state data to develop the IPGRs. The IPGR from the 2022 Steam Trap Monitoring CASE Report was calculated using an average of the 10-year and 30-year compound annual growth rate (CAGR) of INDPRO, the national Federal Industrial Production Index (Johnson, Heinrichs, & Coakley, 2020). However, the Statewide CASE Team determined that national trends would not provide an accurate representation of the California industrial production market. While California is the largest contributor to the U.S. manufacturing industry in terms of output and employment, it accounts for just 14.5 percent of U.S. manufacturing output (Profozich, 2022). A study performed by Beacon Economics for the California Manufacturing Network confirmed that California's manufacturing sector has grown at a faster rate compared with that of the entire United States (Economics, n.d.).

To more accurately estimate California's IPGR, the Statewide CASE Team consulted with Beacon Economics to identify California-specific data on industrial production growth and the differences between California's manufacturing sector and the U.S. manufacturing sector as a whole. Beacon Economics provided a 2025 study demonstrating that California's manufacturing growth was not only faster than the rest of the United States, but California's manufacturing is also more productive (Beacon Economics, 2025). The Statewide CASE Team investigated California real Gross Domestic Product (GDP) data from the U.S. Bureau of Economic Analysis (BEA) and California Federal Reserve Bank of St. Louis' Federal Reserve Economic Data (FRED) for industries classified as manufacturing per the 2017 North American Industry Classification System (NAICS).

The Statewide CASE Team calculated the average of the 7-year CAGR and 10-year CAGR from both sources through 2024. The California real GDP manufacturing growth rate from BEA and FRED was similar at 2.25 percent and 2.74 percent, respectively. The BEA data provided a more conservative growth rate and was selected for California IPGR calculations.

To further tailor this data to the proposed condensate return measure, the Statewide CASE Team applied weights based on the proportion of boiler capacity in each of the main industry subsectors (i.e., food and beverage manufacturing, wood manufacturing, and total other manufacturing which is defined as all other manufacturing that was not food and beverage, wood, lumber, petroleum/refining, or other subsectors that burn byproduct waste), calculated from the statewide boiler inventory based on AQMD data to subsector-specific California real GDP BEA data. Boiler capacity from canneries was excluded from the weighted average for year-round boilers. The calculated weighted average IPGR for year-round boilers was 1.65 percent. The growth rate for the seasonal boilers is best represented by the Food and Beverage Manufacturing IPGR of 0.46 percent, which was calculated from BEA real GDP data in 2017 chained dollars.

Because the condensate return measure does not apply to replacement boilers or steam loads, the Statewide CASE Team separated estimates of new steam loads at new facilities from those loads added to existing facilities. The Statewide CASE Team then split out the year-round and seasonal IPGRs between growth at new facilities (new construction) and growth at existing facilities (additions and alterations). The Statewide

CASE Team estimated that 90 percent of new steam load growth would occur at existing facilities and 10 percent would occur in new construction projects. Statewide savings estimates were calculated using the growth rates in Table 55.

Table 55: Estimated Industrial Production Growth Rates: Steam Loads

Steam Load Type	New Construction	Alterations and Alterations
Year-Round Steam Loads	0.17%	1.49%
Seasonal Steam Loads	0.05%	0.41%

The new construction and additions and alterations forecasts are equivalent to the Existing Steam Boiler Stock multiplied by the steam load IPGRs for each category. The Statewide CASE Team multiplied the per-unit measure savings by each forecast to get statewide savings. Natural market adoption is accounted for through the Standard Design assumptions as outlined in Appendix A.

The energy impacts of the proposed code changes do not vary by climate zone. The measures are not climate-dependent because the impact of the outdoor air temperature on the operation of steam systems is minimal and does not materially impact estimated measure savings. Since savings do not vary by climate zone, the Statewide CASE Team used the statewide LSC hourly factors when calculating energy and LSC impacts.

Table 56, Table 57, and Table 58 show the percentages of statewide boiler capacity that would be impacted by the proposed code changes in 2029 among boilers with input capacities over 10 MMBtu/h. These percentages take into account the industries that are not impacted by Title 24, Part 6, and the exceptions for each measure. The estimated market share of compliance with the requirement is accounted for through the assumptions in the baseline case used to calculate energy savings and is not represented in the tables below. The Statewide CASE Team developed these estimates using the methods described in this section. No differences in affected boiler capacity are found by climate zone.

Table 56: Percentage of Statewide Boiler Capacity Impacted by Proposed Code Change in 2029, by Prototype – Condensate Return

Boiler Category	New Construction Impacted (Percent Capacity)	Existing Boiler Capacity (Additions and Alterations) Impacted (Percent Capacity)
Year-Round Boiler 10-15 MMBtu/h	44.7%	0.9%
Year-Round Boiler 15-25 MMBtu/h	44.1%	0.9%
Year-Round Boiler 25-50 MMBtu/h	43.6%	0.9%
Year-Round Boiler 50-100 MMBtu/h	22.0%	0.5%
Year-Round Boiler 100-200 MMBtu/h	45.0%	0.9%
Year-Round Boiler 200+ MMBtu/h	13.2%	0.3%
Seasonal Boiler 10-15 MMBtu/h	45.0%	0.3%
Seasonal Boiler 15-25 MMBtu/h	45.0%	0.3%
Seasonal Boiler 25-50 MMBtu/h	45.0%	0.3%
Seasonal Boiler 50-100 MMBtu/h	45.0%	0.3%
Seasonal Boiler 100-200 MMBtu/h	45.0%	0.3%
Seasonal Boiler 200+ MMBtu/h	45.0%	0.3%

Table 57 presents the projected new process boiler capacity that the proposed code changes would respectively impact in 2029.

Table 58 shows the projected existing statewide boiler capacity that the proposed code changes would affect through additions and alterations in 2029. The Statewide CASE Team developed these estimates using the methods described earlier in this section. The 2028 CASE Methodology Report includes additional information about the methodology and assumptions used to calculate statewide energy impacts.

Table 57: Estimated New Process Boiler Capacity Impacted by Proposed Condensate Return Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.0	0.2	1.2	0.5	0.1	0.9	0.6	1.3	1.6	1.3	0.3	2.0	1.4	0.2	0.2	0.1	12.0
Year-Round 15-25 MMBtu/h	0.0	0.2	1.1	0.5	0.2	1.1	0.4	1.5	1.9	1.3	0.2	2.4	2.4	0.4	0.3	0.1	14.0
Year-Round 25-50 MMBtu/h	0.1	0.2	1.4	0.7	0.3	1.3	0.5	1.4	2.0	1.3	0.3	3.7	3.0	0.5	0.2	0.2	17.1
Year-Round 50-100 MMBtu/h	0.0	0.1	2.3	0.4	0.1	0.2	0.2	0.3	0.4	0.4	0.1	12.6	18.7	0.4	0.2	0.1	36.5
Year-Round 100-200 MMBtu/h	0.0	0.3	1.6	0.7	0.0	0.4	0.0	0.6	0.8	0.4	0.3	4.6	3.8	0.9	0.3	0.2	15.0
Year-Round 200+ MMBtu/h	0.4	0.3	1.2	0.7	0.0	1.9	0.0	3.9	4.4	2.9	2.7	1.2	0.4	1.4	0.8	0.3	22.5
Seasonal 10-15 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal 15-25 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal 25-50 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Seasonal 50-100 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.6
Seasonal 100-200 MMBtu/h	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.5	0.4	0.1	0.0	0.0	1.7
Seasonal 200+ MMBtu/h	0.0	0.0	0.1	0.1	0.0	0.2	0.0	0.4	0.5	0.3	0.3	0.1	0.0	0.2	0.1	0.0	2.4
TOTAL	**0.6**	**1.4**	**9.1**	**3.7**	**0.7**	**6.2**	**1.7**	**9.5**	**11.7**	**7.9**	**4.2**	**27.4**	**30.5**	**4.2**	**2.1**	**1.1**	**121.9**

Table 58: Estimated Existing Process Boiler Capacity Impacted by Proposed Condensate Return Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Category	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.2	1.9	10.7	4.9	1.3	8.4	5.5	11.7	14.5	11.3	2.4	18.0	12.8	2.1	1.8	0.8	108.1
Year-Round 15-25 MMBtu/h	0.0	1.7	9.7	4.4	1.7	9.7	3.3	13.9	17.0	11.9	2.0	21.6	21.4	3.7	3.0	1.3	126.2
Year-Round 25-50 MMBtu/h	0.9	2.1	12.7	6.3	2.7	12.1	4.4	12.4	18.3	11.3	2.5	33.0	27.3	4.2	1.7	1.7	153.6
Year-Round 50-100 MMBtu/h	0.0	1.3	20.8	3.6	0.9	1.9	1.9	3.1	3.5	3.2	1.3	113.0	168.1	3.6	1.5	0.7	328.5
Year-Round 100-200 MMBtu/h	0.0	2.5	14.1	6.6	0.0	3.7	0.0	5.2	6.9	3.9	2.6	41.8	34.5	8.5	2.4	1.9	134.6
Year-Round 200+ MMBtu/h	3.6	2.3	11.0	5.9	0.0	17.3	0.0	34.7	39.6	26.0	24.3	10.9	3.4	12.7	7.4	3.1	202.2
Seasonal 10-15 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Seasonal 15-25 MMBtu/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Seasonal 25-50 MMBtu/h	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.2	0.2	0.0	0.0	0.0	0.9
Seasonal 50-100 MMBtu/h	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	1.8	2.7	0.1	0.0	0.0	5.2
Seasonal 100-200 MMBtu/h	0.0	0.3	1.6	0.8	0.0	0.4	0.0	0.6	0.8	0.5	0.3	4.9	4.0	1.0	0.3	0.2	15.6
Seasonal 200+ MMBtu/h	0.4	0.2	1.2	0.6	0.0	1.9	0.0	3.8	4.3	2.8	2.6	1.2	0.4	1.4	0.8	0.3	21.9
TOTAL	**5.1**	**12.3**	**82.3**	**33.3**	**6.7**	**55.6**	**15.2**	**85.5**	**105.1**	**70.9**	**38.0**	**246.4**	**274.7**	**37.4**	**18.9**	**10.0**	**1,097.3**

Appendix D: Environmental Analysis

Flash Steam Recovery

Potential Significant Environmental Effect of Proposal

The Statewide CASE Team has considered the environmental benefits and adverse impacts of its proposal, including but not limited to an evaluation of factors contained in the California Code of Regulations, Title 14, section 15064, and has determined that the proposal will not result in a significant effect on the environment.

Direct Environmental Impacts

Direct Environmental Benefits

Flash steam that is not recovered is vented to the atmosphere, wasting both thermal energy and water. Flash steam recovery systems reduce energy and water consumption by using flash steam to serve low-pressure loads rather than down-regulating live boiler steam. Recovering flash steam therefore saves energy and water. This process in turn reduces GHG emissions from the reduced need to produce that energy, typically by burning natural gas.

The direct environmental benefits of this proposal are demonstrated by the estimated energy reductions, as discussed in Sections 2.5.1 and 2.5.2. The data demonstrating water use benefits are discussed in section 2.5.3.

Direct Adverse Environmental Impacts

The Statewide CASE Team has not identified any direct adverse environmental impacts.

Indirect Environmental Impacts

Indirect Environmental Benefits

The reduction in energy consumption from flash steam recovery would indirectly improve local air quality. Combustion of natural gas produces NOx, a chemical precursor to ozone. Reducing natural gas consumption will therefore indirectly lead to lower ozone (Chen, Omotesho, & Johnson, 2025). In addition, reduced water consumption means that water utilities will spend less energy pumping water for distribution.

Indirect Adverse Environmental Impacts

The Statewide CASE Team has not identified any indirect adverse environmental impacts.

Mitigation Measures

The Statewide CASE Team has considered opportunities to minimize the environmental impact of the proposal, including an evaluation of “specific economic, environmental, legal, social, and technological factors” (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

Reasonable Alternatives to Proposal

The Statewide CASE Team has considered alternatives to the proposal and determined that no alternate proposals would achieve the same impact of reduced boiler energy consumption.

Water Use and Water Quality Impacts Methodology

Recovering flash steam will reduce the amount of water lost to steam venting, and the water saved is calculated as the difference between the baseline and proposed blowdown flash steam mass flows. The quantity of water saved will vary depending on the site’s size and operating characteristics.

Condensate Return

Potential Significant Environmental Effect of Proposal

The Statewide CASE Team has considered the environmental benefits and adverse impacts of its proposal, including but not limited to an evaluation of factors contained in the California Code of Regulations, Title 14, section 15064, and has determined that the proposal will not result in a significant effect on the environment.

Direct Environmental Impacts

Direct Environmental Benefits

Condensate return systems reduce water use by replacing fresh make-up water that would otherwise be needed for boiler feedwater. Fresh make-up water also requires additional heating from the boiler, so replacing it with condensate return also decreases boiler fuel consumption, which in turn reduces GHG emissions.

The data demonstrating energy benefits are discussed in section 3.5.1. The data demonstrating GHG benefits are discussed in section 3.5.2. The data demonstrating the benefits of water use are discussed in section 3.5.3.

Direct Adverse Environmental Impacts

The Statewide CASE Team has not identified any direct adverse environmental impacts that would result from the proposed changes.

Indirect Environmental Impacts

Indirect Environmental Benefits

This reduction in fuel consumption from returning condensate would also indirectly improve local air quality. Combustion of natural gas produces NOx, a chemical precursor to ozone. Reducing the consumption of natural gas will therefore indirectly lead to reduced ozone (Chen, Omotesho, & Johnson, 2025). In addition, reduced water consumption means that water utilities will spend less energy pumping water for distribution.

Indirect Adverse Environmental Impacts

The Statewide CASE Team has not identified any indirect adverse environmental impacts.

Mitigation Measures

The Statewide CASE Team has considered opportunities to minimize the environmental impact of the proposal, including an evaluation of “specific economic, environmental, legal, social, and technological factors” (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine that this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

Reasonable Alternatives to Proposal

The Statewide CASE Team has considered alternatives to the proposal and determined that no alternate proposals would achieve the same impact of reduced boiler energy consumption.

Water Use and Water Quality Impacts Methodology

Returning condensate will reduce water consumption by reducing the amount of water that needs to be replaced in the boiler system. The water savings were calculated by adding the increase in condensate flow and the decrease in blowdown flow between the baseline and proposed cases. The quantity of water saved will vary depending on the site’s size and operating characteristics.

Appendix E: Summary of Stakeholder Engagement

Introduction to Stakeholder Engagement

Collaborating with stakeholders who may be affected by proposed code changes is a core component of the Statewide CASE Team's process. The Statewide CASE Team engages interested parties to identify and address issues related to the proposals, to submit recommendations to the CEC that reflect broad support. Public stakeholders provide valuable feedback on draft analyses and help identify and address adoption challenges, including cost effectiveness, market and technical barriers, compliance and enforcement, and potential impacts on human health or the environment. Some stakeholders also provide data that the Statewide CASE Team uses to support analyses.

This appendix summarizes the stakeholder engagement conducted by the Statewide CASE Team during the development and refinement of the report's recommendations.

Flash Steam Recovery and Condensate Return

Utility-Sponsored Stakeholder Meetings

Utility-sponsored stakeholder meetings provide an opportunity to learn about the Statewide CASE Team's role in the advocacy effort and to hear about specific code change proposals that the Statewide CASE Team is pursuing for the 2028 code cycle. The goal of these meetings is to solicit input on proposals from stakeholders early enough to ensure the proposals and the supporting analyses are vetted and have as few outstanding issues as possible. To promote transparency in the development of code change proposals, the Statewide CASE Team uses stakeholder meetings to solicit feedback on the following:

- Proposed code changes;
- Draft code language;
- Draft assumptions and results of analyses;
- Data to support assumptions;
- Compliance and enforcement; and
- Technical and market feasibility.

The Statewide CASE Team hosted two stakeholder meetings for the proposed process steam measures via webinar, as described in Table 59. Dates and links to event pages on Title24Stakeholders.com are provided in this section. Materials from each meeting, such as slide presentations, proposal summaries with code language, and meeting notes, are included in the bibliography section of this report.

Table 59: Utility-Sponsored Stakeholder Meetings

Meeting Name and Link to Materials	Meeting Date	Summary of Items Discussed
First Round of Process Steam Utility-Sponsored Stakeholder Meetings	Wednesday, October 29, 2025	• Proposal description • Market and technical considerations • Energy savings methodology and cost assumptions • Compliance verification
Second Round of Process Steam Utility-Sponsored Stakeholder Meetings	Tuesday, March 17	• Market and technical considerations • Energy savings methodology and assumptions • Cost assumptions

The first round of utility-sponsored stakeholder meetings began in October 2025 and served as an early forum to promote transparency and gather stakeholder feedback on measures under consideration by the Statewide CASE Team.

The objectives of the first round of stakeholder meetings were to solicit input on the scope of the 2028 code cycle proposals; request data and feedback on the specific approaches, assumptions, and methodologies for the energy impacts and cost-effectiveness analyses; and understand potential technical and market barriers. Initial draft code language was posted on Title24Stakeholders.com for public stakeholder review.

The second round of utility-sponsored stakeholder meetings were held in early 2026 to provide updated details on proposed code changes. These meetings introduced early results of energy, cost effectiveness, and incremental cost analyses and assumptions.

Both utility-sponsored stakeholder meetings were open to the public. For each stakeholder meeting, two promotional emails were distributed from info@title24stakeholders.com. One email was sent to the full Title 24 Stakeholders listserv, which includes over 3,000 individuals. A second email targeted specific recipients based on their subscription preferences.

The Title 24 Stakeholders listserv is an opt-in service comprising participants from a diverse industries and trades, such as manufacturers, advocacy groups, local government, and building and energy professionals. Each meeting was announced on the Title 24 Stakeholders LinkedIn page and cross-promoted on the CEC LinkedIn page approximately two weeks in advance to engage individuals, organizations, and broader channels outside beyond the listserv. The Statewide CASE Team conducted extensive personal outreach to stakeholders identified in initial work plans who had not yet opted in to the listserv. Exported webinar meeting data captured attendance numbers, individual comments, and results from live attendee polls to help evaluate stakeholder participation and support.

Statewide CASE Team Communications

The Statewide CASE Team held personal communications over email and phone with numerous stakeholders when developing this report, listed in Table 60. Most stakeholders preferred to be anonymous.

Table 60: Engaged Stakeholders

Organization/ Individual Name	Market Role	Date of Engagement	Mentioned in CASE Report Sections
Anonymous Stakeholder 1	Boiler systems manufacturer	July-September 2026	2.3.1.2 Market Challenges and Solutions 3.1.2 Benefits of Proposed Change 3.3.1.1 Current Market and Structure Availability
Anonymous Stakeholder 2	Boiler and steam system representative	July-November 2025	3.3.1.1 Current Market and Structure Availability 3.3.2.3 Design and Construction Challenges and Solutions
Anonymous Stakeholder 3	Industrial energy benchmarking representative	September 2025	Did not inform specific assumptions for the CASE Report.
T. Berry	Sales representative, manufacturing equipment	November 2025	3.3.2.1 Market Challenges and Solutions
R. Baker	California Technical Forum	November 2025	Did not inform specific assumptions for the CASE Report.
Beacon Economics	Economic research and consulting firm	August 2025	Appendix C: Assumptions for Statewide Savings Estimates.
Anonymous Stakeholder 4	Steam and water treatment services	November 2025	Did not inform specific assumptions.
Anonymous Stakeholder 5	Controller manufacturer	January 2026	Did not inform specific assumptions.
Anonymous Stakeholder 6	Government safety agency	February 2026	2.1.5.2 Interactions with Other Regulations 2.2.1 Compliance Considerations
Anonymous Stakeholder 7	Manufacturer of thermal utility management systems	February 2026	2.3.1.2 Market Challenges and Solutions

Engagement with ESJ communities

The Statewide CASE Team did not conduct stakeholder outreach specifically targeted towards ESJ communities for this proposed code change. The proposed measures would have no direct impact on residential communities in California, and the only indirect anticipated impact is decreased exposure to air pollution due to reduced natural gas combustion at nearby industrial facilities.

Mass Email Cold Outreach

The Statewide CASE Team leveraged a list of organizations and emails from the California Directory of Manufacturers to send cold outreach emails to about 600 organizations believed to have process boilers or steam systems. The email invited respondents to participate in a conversational interview about or otherwise provide feedback on the proposed measures. Many of the email addresses were outdated at the time of sending, and the Statewide CASE Team did not receive responses from any stakeholders who wished to contribute to the process.

Appendix F: Code Language Markup (Non-restructured)

The language below is in the non-restructured 2025 Title 24 Part 6 Code Language.

Flash Steam Recovery – Proposed Code Language

Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes to the 2025 documents should be marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

Energy Code (Title 24, Part 6)

SECTION 100.1 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 100.1(b) – Definitions: Recommends new or revised definitions for the following terms:

FLASH STEAM is water vapor that is generated when condensate is dropped to a pressure lower than its saturation pressure, which then vaporizes a fraction of the liquid in a process called flashing.

PRESSURIZED CONDENSATE RETURN is a steam condensate return system that continuously operates at a pressure above 15 psig during normal operation and is not vented to atmosphere. The system contains liquid condensate and any associated steam vapor that may be present in the piping.

SUBCHAPTER 3 – NONRESIDENTIAL, HIGH-RISE RESIDENTIAL, HOTEL/MOTEL OCCUPANCIES, AND COVERED PROCESSES--MANDATORY REQUIREMENTS

SECTION 120.6 – MANDATORY REQUIREMENTS FOR COVERED PROCESSES

120.6(d)4 Mandatory requirements for process boilers.

4. Any newly installed process steam boilers with capacities at or above 10 MMBtu/h that have or are connected to a system with a pressurized deaerator are required to recover and route flash steam from blowdown to the deaerator or another heating load.

Exception 1 to 120.6(d)4: Newly installed process steam boiler systems where high-pressure condensate is returned to the deaerator without being flashed (dropped to atmospheric pressure).

Exception 2 to 120.6(d)4: Newly installed process steam boiler systems where the linear distance (sum of horizontal and vertical) from the boiler to the serving deaerator is greater than or equal to 100 feet.

Condensate Return – Proposed Code Language

Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes to the 2025 documents should be marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

Energy Code (Title 24, Part 6)

SECTION 100.1 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 100.1(b) – Definitions: Recommends new or revised definitions for the following terms:

CONDENSATE RETURN SYSTEM is a system designed to return steam condensate to a boiler plant for reuse that includes piping and may also include condensate collection tanks and mechanical pumping.

PROCESS STEAM SYSTEM is a steam system that has one or more connected process boilers and serves one or more process loads.

PROCESS, COVERED is a process that includes computer rooms, data centers, elevators, escalators and moving walkways, laboratories, enclosed parking garages, commercial kitchens, refrigerated warehouses, commercial refrigeration, compressed air systems, process boilers, process steam systems, process heating and cooling piping, and controlled environment horticultural spaces.

SUBCHAPTER 3 – NONRESIDENTIAL, HIGH-RISE RESIDENTIAL, HOTEL/MOTEL OCCUPANCIES, AND COVERED PROCESSES--MANDATORY REQUIREMENTS

SECTION 120.6 – MANDATORY REQUIREMENTS FOR COVERED PROCESSES

120.6(l) Mandatory requirements for process steam loads.

1. Condensate return. The following requirements apply to all new, non-replacement process steam loads that use indirect-contact heat exchangers at new and existing facilities that meet the below conditions:

a. have one or more connected boilers with an input rating (capacity) of 10 MMBtu/h or greater, and
b. meet the criteria for load size and linear distances in Table 120.6-A
    a. The linear distance shall be measured from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

TABLE 120.6-A STEAM LOAD CONDENSATE RETURN DISTANCE CODE TRIGGER CRITERIA

Steam Flow (lb/h)	**Linear Distance[16] (ft) Less Than**
<1,000	Exempt
≥1,000, <2,000	400
≥2,000, <3,000	600
≥3,000, <4,000	800
≥4,000, <6,000	1,100
≥6,000	1,300

Qualifying process steam loads shall install a condensate return system to return all condensate, including condensate from new drip leg steam traps associated with the load, to the boiler plant for reuse.

All steam loads that do not qualify for 120.6(l)2 based on the criteria in Table 120.6-A shall include the following in the steam system construction documents:

a. Linear distance (sum of horizontal and vertical) from the steam trap serving the

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[16] Footnote to TABLE 120.6-A: Linear distance (sum of horizontal and vertical) from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer.

Exception to Section 120.6(l)1: Process steam systems in hotel/motel buildings and nonresidential buildings with Group R occupancies.