Calculation of Sump Fluid Temperature During Loss of Coolant Accidents at a Sample Nuclear Power Plant

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Prepared by

W. Arcieri
R. Beaton
D. Fletcher
J. Lehning (USNRC)

Information Systems Laboratories, Inc.
11140 Rockville Pike, Suite 500
Rockville, MD 20852

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1.0 Introduction

The U.S. Nuclear Regulatory Commission is evaluating the safety issues associated with degradation of emergency core cooling system (ECCS) pump performance as a result of clogging of the screens and/or pump suction piping. Clogging may occur due to either debris in the sump water or chemical reactions that form slurries that lead to clogging. The sump water temperature is expected to be an important factor in the formation of slurries. In addition to the sump temperature, containment pressure is a key parameter in determining Net Positive Suction Head (NPSH) margin.

The purpose of this report is to document the analysis of sump fluid temperature and containment pressure in a sample nuclear power plant following a loss of coolant accident. This analysis is intended to determine a realistic, but conservative sump water temperature/pressure. An existing RELAP5 plant model was used as the basis for the sump water temperature calculations. A simplified containment model with the important features that affect sump water temperature was incorporated into the RELAP5 model. These features include the containment spray loop including the shutdown cooling system heat exchangers.

2.0 RELAP5 Model Description

The sample nuclear power plant is a pressurized water reactor of Combustion Engineering design with a rated thermal power around 2,500 MW. The reactor coolant system consists of a reactor vessel and two coolant loops connected in parallel and designated as Loops 1 and 2. Each coolant loop includes hot leg piping, an inverted U-tube type steam generator, and two sets of reactor coolant pumps and cold leg piping. The cold legs and reactor coolant pumps on each loop are designated as A and B. The normal coolant flow on each loop is from the reactor vessel outlet nozzle, through the hot leg, steam generator, reactor coolant pumps and cold legs to the reactor vessel inlet nozzle. A pressurizer is connected via a surge line to the hot leg on Loop 1. The electrically-heated pressurizer provides pressure control for the reactor coolant system. Two pressurizer spray lines are routed from one of the pump-discharge cold legs on each loop through control valves to a spray nozzle in the pressurizer upper dome. Reactor coolant system overpressure protection is provided by safety relief valves atop the pressurizer (the plant also employs power operated relief valves, but they are blocked closed during normal plant operation). Emergency core cooling functions are provided by high and low pressure injection systems and safety injection tanks, which are connected to each of the four cold legs at the pump-discharge. A charging/letdown system performs the functions of reactor coolant system water chemistry control and pressurizer level control. Decay heat removal capability from the steam generators is provided by motor-driven and turbine-driven auxiliary feedwater systems that discharge into the steam generator downcomers. The maximum auxiliary feedwater flow that may be delivered to each steam generator is automatically limited. Steam generator secondary system overpressure protection is provided by safety relief valves, atmospheric dump valves and turbine bypass valves located on the main steam lines. Main steam isolation valves are located in each of the two steam lines, limiting the influence that a break in one of the steam generator secondary systems would have on the other.

The sample plant containment is a large-dry design that completely encloses the reactor and primary coolant system in order to minimize the release of radionuclides to the environment if a serious failure of the primary coolant system pressure boundary should occur. The containment is designed to ensure that leakage will not exceed 0.1% volume per day by weight at a design pressure of 70 psia [0.48 MPa] and a design temperature of 283°F [412 K].

The containment sump is located at the center of the containment floor. The containment sump pit surface area is 622 ft^2 [57.8 m^2]. A sump depth of 5 ft [1.52 m] is assumed (estimated from drawings). Principal containment dimensions are listed below.

Table 1: *Principal Containment Dimensions*

Parameter	Value
Inside Diameter	116 ft [35.4 m]
Inside Height (Including Dome)	189 ft [57.6 m]
Vertical Wall Thickness	3.5 ft [1.07 m]
Dome Thickness	3.0 ft [0.914 m]
Interior Free Volume	1,640,000 ft^3 [46,439 m^3]
Sump Pit Surface Area	622 ft^2 [57.8 m^2]
Sump Depth	5.0 ft [1.52 m]

Engineered safeguards systems are provided to cool and depressurize the containment in addition to limiting the consequences of a design basis accident. Systems that directly provide containment cooling are the containment air cooler system and the containment spray system. The containment air cooling system removes heat directly from the containment atmosphere to the service water system with recirculating fans and cooling coils. The containment spray system removes heat directly from the containment atmosphere by cold water quenching of airborne steam and subsequent heat removal by recirculation of the containment sump water through the shutdown cooling system heat exchangers.

During a design basis accident, the containment spray system is initiated by a containment high-pressure signal (19.7 psia [0.136 MPa]) or by remote-manual operation from the control room. Initially, the spray system pumps draw from the safety injection reactor water storage tank (SIRWST). Once the tank water inventory reaches low level, the spray pump suction is switched to the containment sump. The recirculated water is cooled by the component cooling water in the shutdown cooling (SDC) heat exchangers prior to being discharged into the upper containment region through the spray nozzles.

The shutdown cooling system consists of three half-capacity pumps, two shutdown cooling heat exchangers and associated piping, instruments, and accessories. The operating parameters and heat removal capability of each SDC heat exchanger at 27.5 hours after shutdown are listed in Table 2.

Table 2: *Heat Removal Capability of SDC Heat Exchanger*

Parameter		Value*
Tube Side	Flow	1,500,000 lbm/hr [189 kg/s]
	Inlet Temperature	130°F [328 K]
	Outlet Temperature	111.7°F [317 K]
Shell Side	Flow	2,000,000 lb/hr [252 kg/s]
	Inlet Temperature	90°F [305 K]
	Outlet Temperature	103.5°F [313 K]
	Heat Transfer	27,500,000 BTU/hr [8.06 MW]

* at 27.5 hours after shutdown

The heat removal capacity of the SDC heat exchangers is 83.5 MBTU/hr [24.5 MW] based on 4,000 gpm [252 L/s] cooling water flow at 114°F [319 K] inlet temperature and 1,420 gpm [89.6 L/s] of spray water at 283°F [413 K] inlet temperature.

The RELAP5 model used is a detailed thermal-hydraulic representation of the sample nuclear power plant that includes the major components of the primary and secondary coolant system and plant control systems. This model was adapted for the calculation of the sump water temperature. Figures 1 and 2 show the noding diagram for the RELAP5 model.

A simplified containment model was added as the original model did not include the containment. The nodalization of this model is presented in Figure 3. The containment volume is modeled as a 10 node pipe. The sump (volume 900-01) is modeled at the bottom of the containment. A time-dependent junction (component 935) is used to represent the containment spray pump that is connected to the SDC heat exchangers. The outlet of the SDC heat exchangers is connected to both containment spray piping and also to the high-pressure safety injection (HPSI) piping. This connection models the HPSI pump suction realignment to the containment sump upon the switchover to containment sump water recirculation mode after the SIRWST water is depleted. The remaining spray piping and connection to the top of the containment are represented by components 950 (10 node pipe) and 955. Component 955 is a connecting junction between the spray piping and the top of the containment volume. A time-dependent volume/junction pair is used to model containment spray when the spray pumps are drawing water from the SIRWST. No special spray model is incorporated into the containment model as the approach used condenses all of the steam in the containment, which is expected during spray operation in the actual plant. Containment atmosphere initial conditions were assumed to be 100°F, 14.7 psia, and 0.9999 static quality. Perturbations to these initial conditions were not considered likely to influence the report conclusions significantly.

The containment air coolers were not included in the simplified containment model on the basis that the principal role of the air coolers is to reduce the air temperature during a LOCA to help control the containment pressure. Including the air coolers could cause the sump water temperature to be somewhat lower that predicted in this report. However, as the goal of the analysis is to determine a realistic, but conservative sump water temperature, it was decided to ignore the impact of the containment air coolers, which is conservative. Also, the containment walls were assumed to be adiabatic, based on the judgement that the structural concrete walls and floor would generally be cooler than the containment atmosphere and will, on average, transfer heat out of the containment. Combined with the containment air cooler assumption, this assumption supports the goal of a realistic, but conservative sump water temperature.

Other minor changes made to the original model include renodalization of the two-dimensional reactor vessel downcomer to a one-dimensional model. Also, the downcomer was further renodalized to avoid Courant-limit issues in the connecting nodes between the cold leg connection and the downcomer to facilitate the long problem run times for the sump temperature analyses. This renodalization preserved the downcomer and cold leg dimensions so as not to introduce any geometry-related changes to the steady state and transient results from the model. A constant reactor power level is modeled until reactor trip; afterward reactor power decay is modeled based on the ANS-79 decay heat standard. Note that the nominal decay heat load was increased by a factor of 2σ for conservatism and then multiplied by a factor of 1.2 to account for uncertainties.

Full ECCS modeling is included in the RELAP5 model. These models include the safety injection tanks, the low pressure injection system and the high pressure injection system. Water temperature for the HPSI and low-pressure safety injection (LPSI) is 87.9°F [304 K] during the period that the HPSI and LPSI pumps are drawing from the SIRWST. The LPSI pumps are automatically tripped off upon switchover to sump recirculation mode. The safety injection tank water temperature is 100°F [310 K]. The safety injection tanks are set to discharge when the primary system pressure drops below 214.7 psia [1.48 MPa].

Note that the entire reactor system shown in Figures 1 and 2 is assumed to be inside containment. In actuality, certain components of the main steam system such as the secondary relief valves and the atmospheric dump valves are located outside containment. The impact of this modeling approach on the sump water temperature is negligible since the valves do not open for any significant period of time for the LOCA transients that are analyzed.

The SDC heat exchangers are modeled as a pipe (12 nodes) connected to a heat structure with an assumed heat transfer area of 200 ft^2 [18.6 m^2] for 2 heat exchangers. Using a tube side inlet temperature of 130°F [328 K] and an average shell side temperature of 96.75°F [309 K], the tube side heat transfer coefficient was adjusted until a heat transfer rate of 27.5 MBTU/hr [8.06 MW] was achieved using the tube side flow rate given in Table 2 (1.5 Mlb/hr [189 kg/s]). The model was checked against the SDC heat exchanger design data and found to transfer 83.5 MBTU/hr [24.5 MW] using a shell side temperature of 130°F [328 K] and 1,420 gpm [89.6 L/s] of spray water at and inlet temperature of 283°F [413 K]. An infinite heat transfer coefficient was used on the shell-side of the tubes.

Steady state initialization at hot full power conditions was performed with the RELAP5 model to establish model initial conditions from which to initiate transient calculations. Two steady state models were developed for the situation where one and two SDC heat exchangers are operating. Steady state runs of 5,000 s were performed for each case. Table 3 compares the calculated steady state results at the end of the runs with plant data. This table shows that the calculated results are in excellent agreement with the plant data. Figures 4 and 5 compare the cold leg pressure and fluid temperature responses over the 5,000 s steady state. This Figure shows that the RELAP5 solutions are steady by the end of the calculation.

Table 3: *Comparison of RELAP5 Steady State Results to Plant Data*

Parameter	Plant Data	Two SDC	One SDC
Reactor thermal power (cntrlvar-999)	2,530 MWt	2,530 MWt	2,530 MWt
Reactor coolant temperature at vessel inlet (tempf-50001)	537°F [554 K]	537°F [554 K]	537°F [554 K]
Reactor coolant temperature at vessel outlet (tempf-56002)	583°F [579 K]	583°F [579 K]	583°F [579 K]
Pressurizer pressure (p-19010)	2,060 psia [14.2 MPa]	2,060 psia [14.2 MPa]	2,060 psia [14.2 MPa]
Reactor coolant flow at core inlet (mflowj-52501)	38,335 lbm/s [17,388 kg/s]	40,288 lbm/s [18,274 kg/s]	40,288 lbm/s [18,274 kg/s]
Pressurizer level (cntrlvar-821)	57%	57%	57%
Main steam flow rate per SG (mflowj-26200)	1,528 lbm/s [693 kg/s]	1,533 lbm/s [695 kg/s]	1,533 lbm/s [695 kg/s]
Main steam pressure (SG dome) (p-26001)	770 psia [5.31 MPa]	757 psia [5.22 MPa]	757 psia [5.22 MPa]

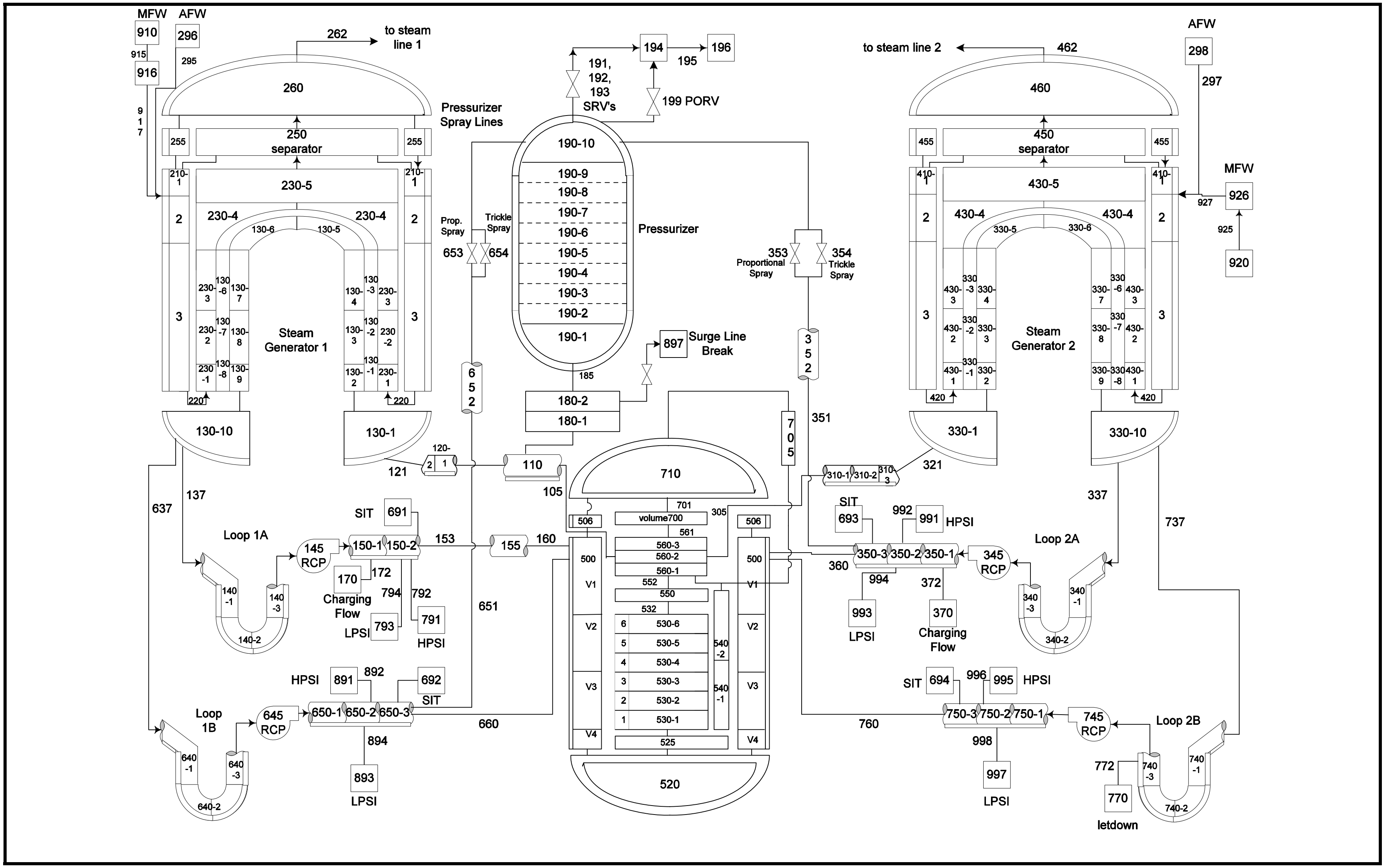

Figure 1: *RELAP5 Model of the Reactor System*

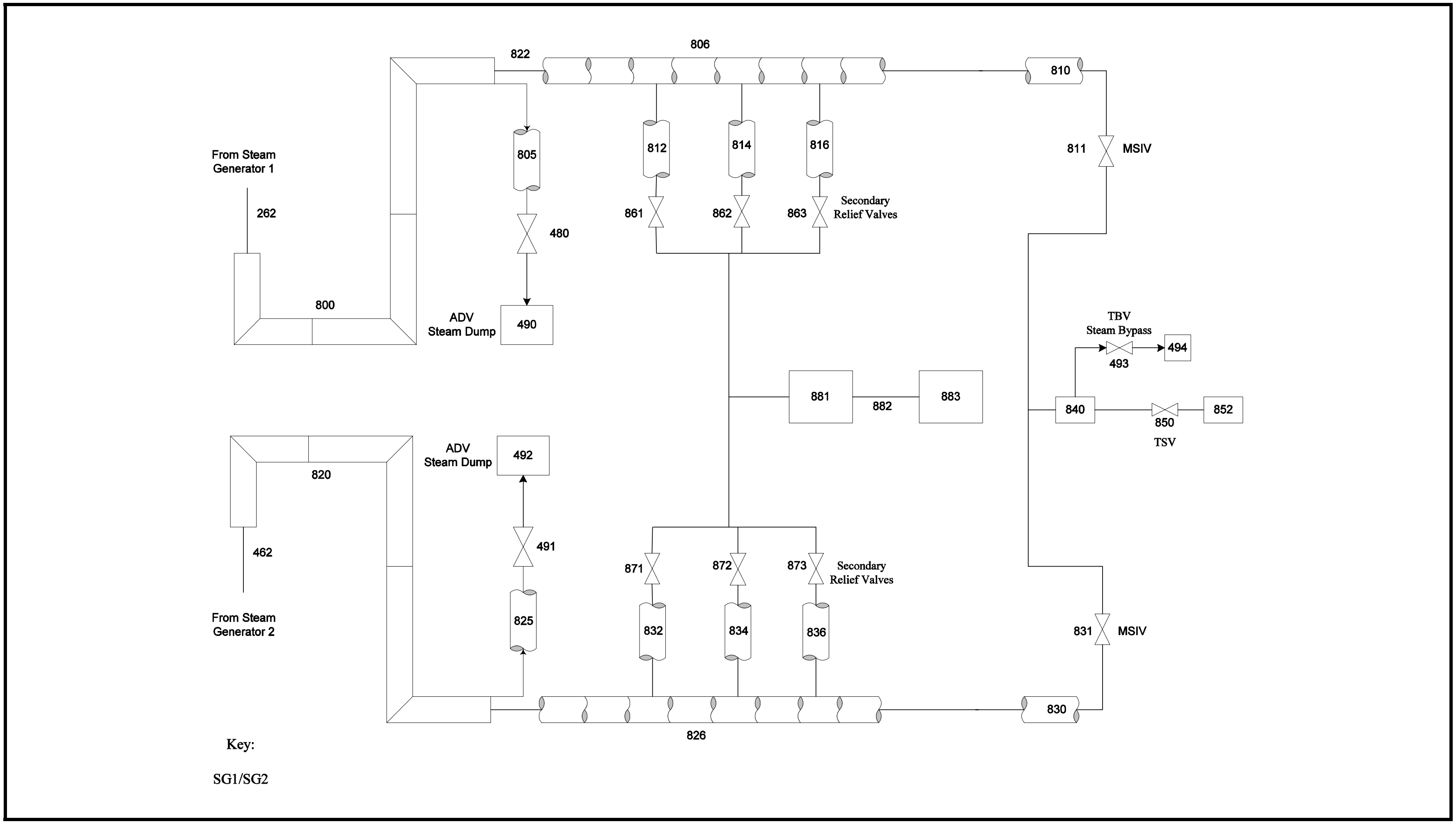

Figure 2: *RELAP5 Model of the Main Steam System*

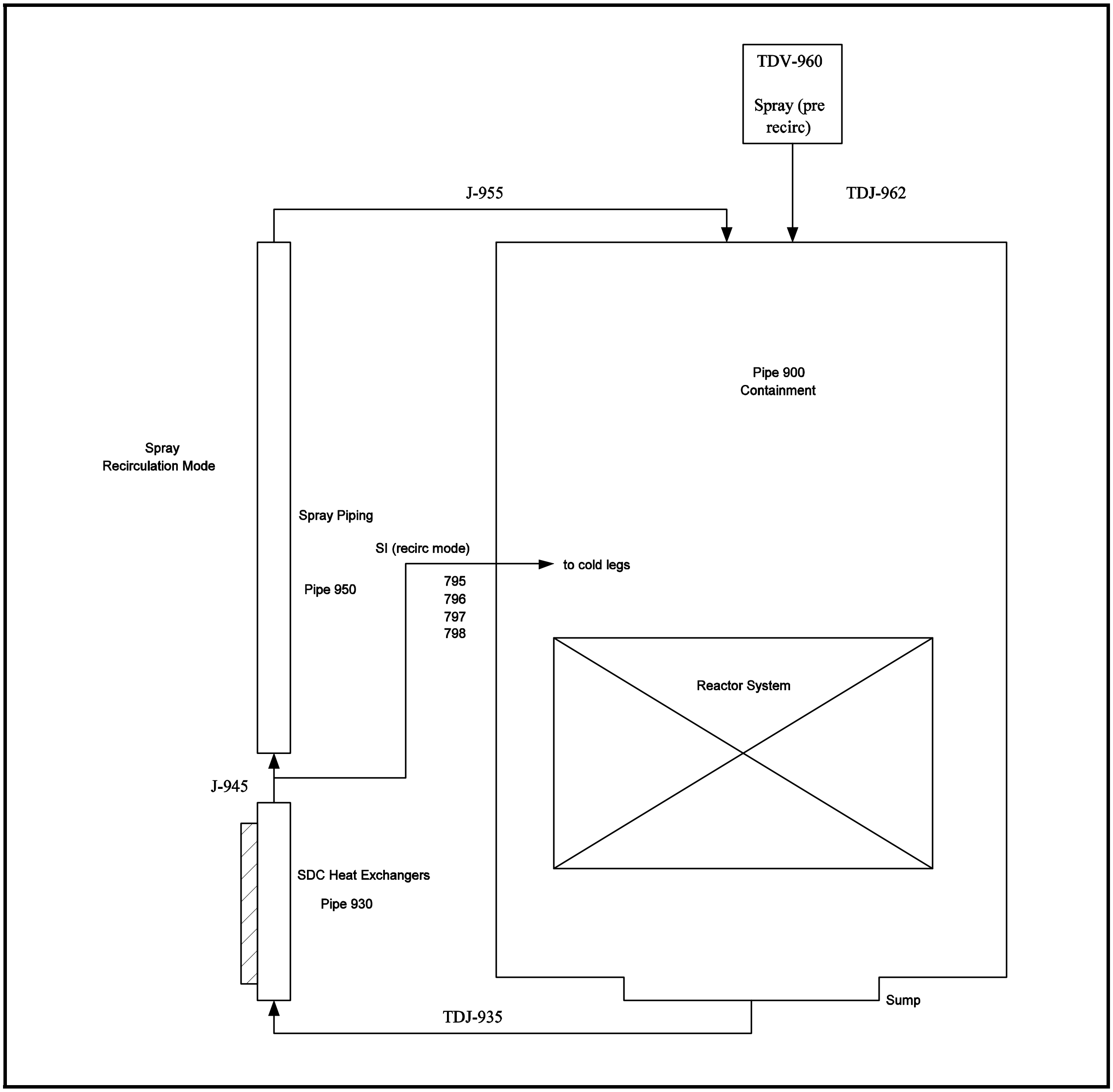

Figure 3: *RELAP5 Model of the Containment*

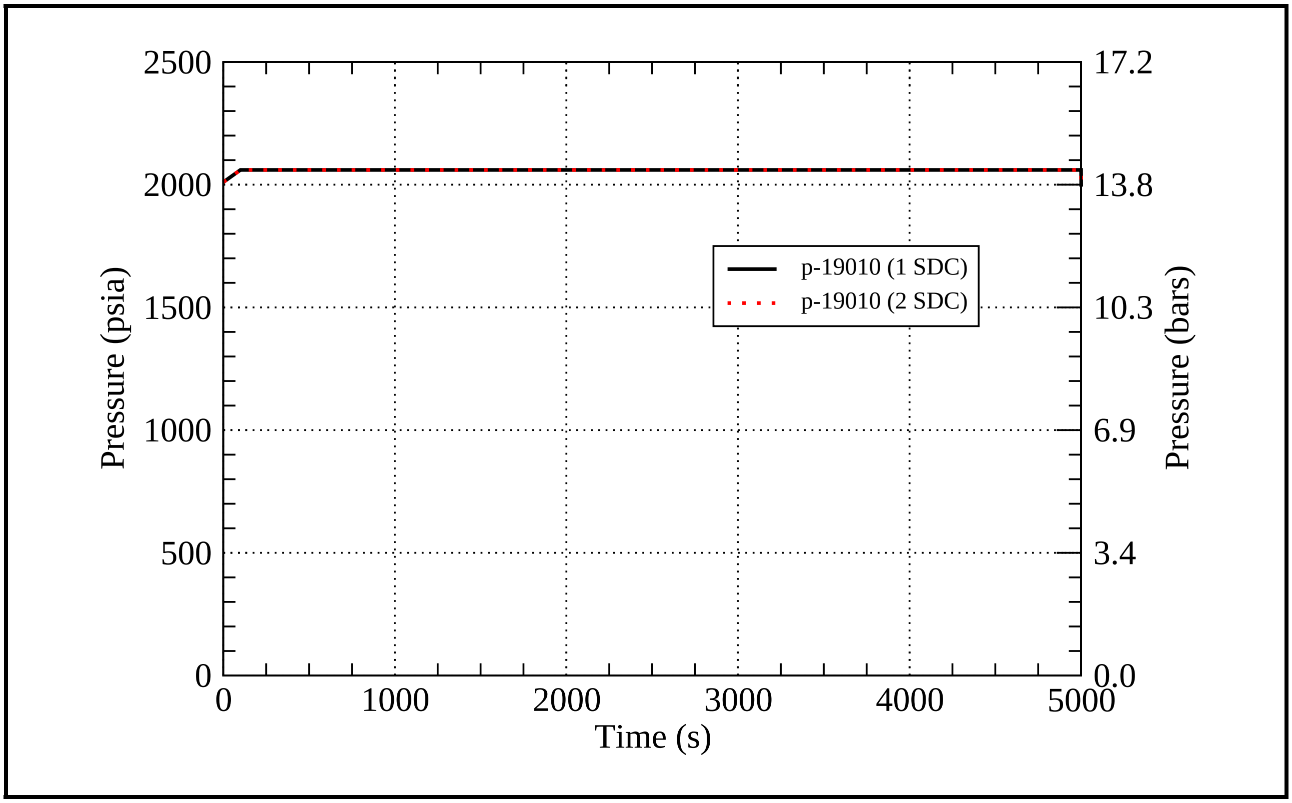

Figure 4: *Pressurizer Pressure at Steady State*

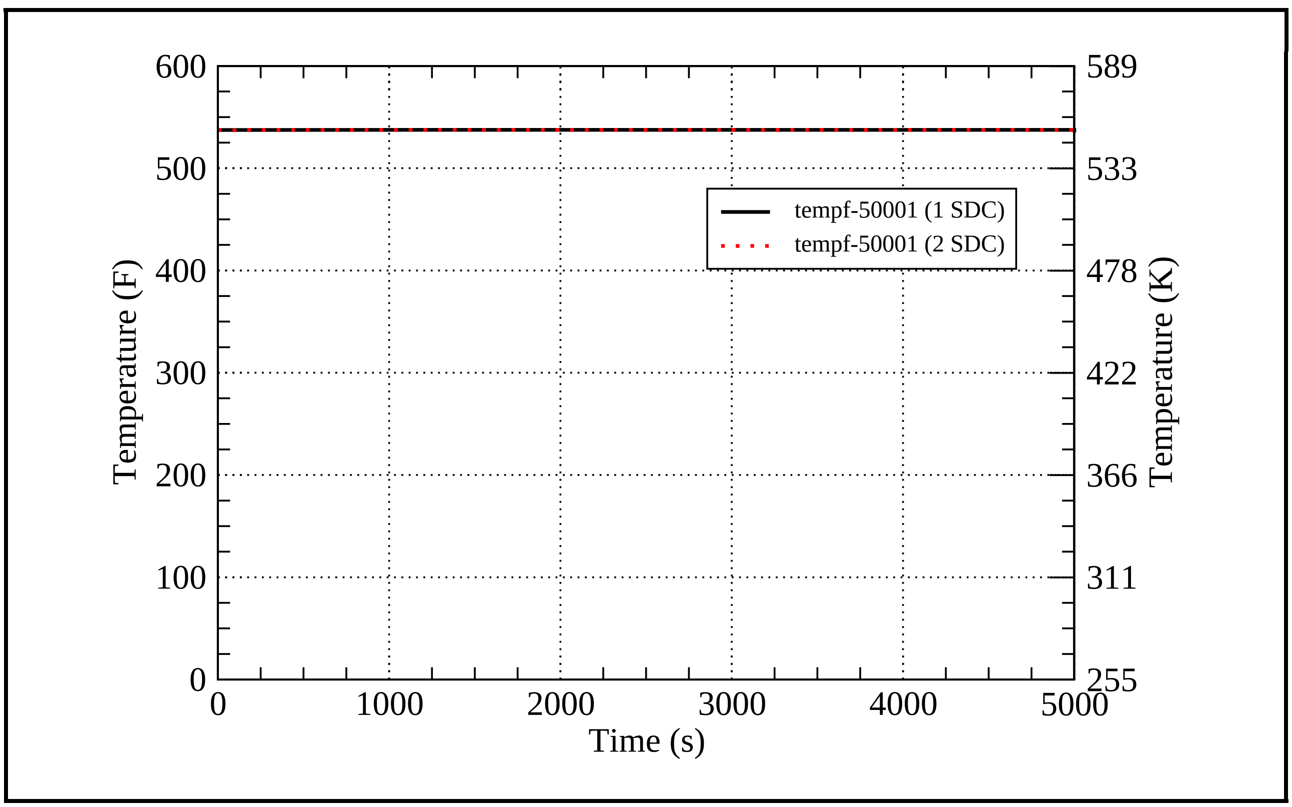

Figure 5: *Reactor Coolant Temperature at Vessel Inlet at Steady State*

3.0 Transient Description

Three different transient events were simulated with RELAP5 using the model described above. These events are all loss of coolant accidents; large break (hot leg), large break (cold leg) and small break (hot leg). Each transient event was simulated with either one or two shutdown cooling (SDC) units (pumps and heat exchangers) for a total of six cases. Three sensitivity cases were also performed with the large hot leg break case where the average shell side temperature of the SDC heat exchanger was changed from 96.75°F [309.1 K] to 130°F [328 K], 60°F [289 K] and 40°F [278 K]. Note that in the case in which the average shell side temperature is increased to 130°F [328 K], one SDC unit is assumed operable since this case is intended to determine the highest expected sump temperature. A final calculation was performed where the sump screens were assumed to become completely blocked ten minutes after switchover to sump recirculation mode. This case is intended to show that there will be fuel damage should the sump screens become blocked.

Large hot leg break cases were assumed to have a flow area of 9.62 ft^2 [0.894 m^2] corresponding to a break diameter of 42 in [1.07 m]. The break was located at the outlet of volume 110. For the cold leg break cases, a double ended guillotine break was assumed. This break is located between the outlet of pipe 150 and inlet of single volume 155. The flow area on each end of the break was 4.9085 ft^2 [0.456 m^2] which corresponds to a diameter of 30 in [0.762 m]. For the small break cases, a flow area of $2.182 \cdot 10^{-2}$ ft^2 [$2.027 \cdot 10^{-3}$ m^2] corresponding to a break diameter of 2.0 in [0.0508 m] was assumed. The small break was located at the outlet of volume 110 (as with the large hot leg break case).

Changes made to simulate one SDC unit (as opposed to the two units previously defined) were made in the steady state model. These changes included reducing the heat exchanger heat transfer area, as well as several flow areas and the SDC pump flow rate, by half.

3.1 Transient Results

Upon break initiation (in all cases), the primary pressure drops, resulting in both a reactor and turbine trip. In making comparisons between the one and two operating SDC units, the cases are equivalent up until the time the switch is made to the sump.

Figures 6 through 8 show the sump fluid temperature for the large hot leg break, large cold leg break and small hot leg break respectively (with both one and two SDC units). Note that in all figures, the top half presents data for 1 day while the bottom shows 30 days. As expected, the sump temperature for the cases with two SDC units decreases sooner than the equivalent case with one SDC unit.

Figure 9 compares the sump fluid temperature for both large breaks and the small break case assuming two SDC units. While the temperatures differ initially over the first few hours, by one day the temperatures for all three cases are almost the same. After 30 days, the temperature difference between the three cases is negligible (about 1°F [0.56 K] maximum difference). This shows that the break size is relatively unimportant in determining the long-term sump temperature response. Table 4 presents the sump fluid temperature at various times for the six cases. Table 5 presents the time when switchover to sump recirculation mode begins.

Table 4: *Sump Fluid Temperature Using Nominal SDC Inlet Temperature*

Break Size	Break Location	# of SDC	Sump Fluid Temperature		
			Maximum	24 hours	30 days
Large	Hot Leg	1	267.4°F [403.9 K]	170.2°F [349.9 K]	124.7°F [324.7 K]
Large	Hot Leg	2	268.1°F [404.3 K]	131.9°F [328.7 K]	110.7°F [316.9 K]
Large	Cold Leg	1	263.6°F [401.8 K]	170.8°F [350.3 K]	124.7°F [324.7 K]
Large	Cold Leg	2	263.2°F [401.6 K]	132.1°F [328.8 K]	110.7°F [316.9 K]
Small	Hot Leg	1	248.1°F [393.2 K]	174.0°F [352.0 K]	125.6°F [325.2 K]
Small	Hot Leg	2	224.5°F [380.1 K]	133.5°F [329.5 K]	111.2°F [317.2 K]

Table 5: *Time of Switchover to Sump Recirculation Mode*

Break Size	Break Location	# of SDC	Time
Large	Hot Leg	1	1,274 s
Large	Hot Leg	2	1,273 s
Large	Cold Leg	1	1,273 s
Large	Cold Leg	2	1,271 s
Small	Hot Leg	1	3,055 s
Small	Hot Leg	2	3,071 s

Figures 10 through 12 present the containment pressure for the large hot leg break, large cold leg break and small hot leg break respectively. These plots show that the containment pressure is initially higher in cases with only one SDC unit operating. This is expected because the one SDC unit does not remove as much energy as cases with two SDC units operating.

Figures 13 through 15 present the heat added/removed for the large hot leg break, large cold leg break and small hot leg break respectively. These plots show that over the first six hours the two SDC units remove more heat than the single SDC unit as expected. After about six hours, the temperature difference across the SDC heat exchanger with two SDC units operating is smaller (because it has previously removed much more heat) than for the single unit. Therefore, the one SDC unit begins to remove more heat than the two SDC units case. This remains true for the duration of the event. For the cases with a single SDC unit, the system initially can not remove all of the decay heat. After about two hours, however, the single SDC system begins removing more than the decay heat, allowing the sump fluid temperature to decrease. By 30 days the system (with either one or two SDC units operating) reaches a quasi-steady condition where decay heat is removed and the sump temperature remains fairly constant.

Figures 16 through 18 present the break flow for the large hot leg break, large cold leg break and small hot leg break respectively. In all cases, the break flow is large initially, then steadies out to reach a quasi-steady condition where break flow is approximately equal to injection flow (from the sump).

Figures 19 through 21 present the primary and secondary reactor coolant system temperatures for large hot leg break, large cold leg break and small hot leg break respectively. These temperatures are at the first node in the hot leg of the broken loop (primary, volume 110) and bottom of the steam generator boiler region (secondary, volume 230). In the case of the large hot leg break, the primary temperature decreases to about 130°F [328 K] at 30 days while the secondary temperature remains hot at just over 400°F [478 K]. Since the primary SG tubes have voided and steam from the core goes out the hot leg break, there is no mechanism for heat transfer between the primary and secondary. In the large cold leg break case, a portion of the core steam must flow around the coolant loops to reach the break. The SG tubes are voided and the hot and cold legs are partially voided. The SG secondary gives up heat to the low pressure and temperature steam flowing through the SG tubes, keeping the primary and secondary temperatures tightly coupled. In the small hot leg break the RCS, including the SG tubes, remains liquid filled. Coolant loop natural circulation continues and the primary and secondary temperatures remain tightly coupled. In reality, the large hot leg break case secondary side would not remain hot as shown in Figure 19, but rather would cool down due to heat losses to containment conditions in the 30 day time period. If the RELAP5 model simulated the heat transfer from the secondary structures to the containment, the heat transfer would be slow (since the structures are insulated) and the SDC system or containment air coolers would remove the additional heat input. Comparing the large hot and cold leg break cases (where in one case the secondary side heat is transferred to the containment) shows that the resulting sump temperatures are similar. Therefore, ignoring the heat transfer from the secondary structures to the containment is acceptable.

Figures 22 through 24 present normalized $NPSH_{available}$ data for the large hot leg break, large cold leg break and small hot leg break respectively. These plots show a calculated parameter representing the subcooling margin of the water in the containment sump. The parameter plotted is $P_{sat}(0) - P_{sat}(t)$, where P represents the pressure margin (expressed as a head) between the sump pressure and the saturation pressure associated with the sump water temperature. $P_{sat}(0)$ is the value of the pressure margin at the time of switchover to the recirculation mode (see Table 5). The plotted parameter thus represents the change in the subcooling margin caused by sump pressure and temperature variations during the transient calculations following the switch to sump recirculation. Initially after sump recirculation begins, the sump temperature in the one SDC unit cases begins to increase (since one SDC cannot initially remove decay heat). This temperature increase causes the pressure difference to decrease resulting in less available pump head. Once the sump temperature begins decreasing, the pressure difference becomes positive resulting in more pump head. In the cases with two SDC units operating, the sump temperature begins to cool down immediately, therefore, resulting in additional pump head.

Figure 25 shows the sump fluid temperature for large hot leg break cases where the SDC inlet temperature (shell side) was varied. This figure shows that as the SDC inlet temperature (shell side) is lowered, the resulting sump temperature is lower as expected. Table 6 presents the sump fluid temperature at various times for the sensitivity cases.

Table 6: *Sump Fluid Temperature For Large Hot Leg Breaks Using Varied SDC Shell Side Temperatures*

SDC average shell side temperature	# of SDC	Sump Fluid Temperature		
		Maximum	24 hours	30 days
130°F [328 K]	1	267.6°F [404.0 K]	204.9°F [369.2 K]	158.1°F [343.2 K]
96.75°F [309 K]	2	268.1°F [404.3 K]	131.9°F [328.7 K]	110.7°F [316.9 K]
60.0°F [289 K]	2	267.3°F [403.9 K]	94.7°F [308.0 K]	73.9°F [296.4 K]
40.0°F [278 K]	2	267.3°F [403.9 K]	74.9°F [297.0 K]	53.9°F [285.3 K]

The final sensitivity case assumes the sump screens become completely blocked. This case was performed with the large hot leg break and one operating shutdown cooling heat exchanger. Since this case will result in high fuel rod temperatures the metal water reaction option was activated in RELAP5. This option required a renodalization of the fuel rod heat structures. This event sequence begins similarly to the cases without sump screen blockage. At 1,277 s, the ECCS is switched to sump recirculation mode. Note this time is slightly different than the similar case results of 1,274 s, where the difference is assumed to be due to the fuel rod heat structure renodalization. Ten minutes after switchover to sump recirculation mode, it is assumed that the sump screens become completely blocked, resulting in zero ECCS flow. The lack of ECCS flow allows the water in the core to begin boiling off. While the core is drying out, the fuel rod temperatures begin to increase and reach 3,500˚F [2,200 K] at 5,074 s, at which point the calculation was stopped. It is assumed at this point that there will be significant damage to the fuel. Figure 26 shows the peak clad temperature while Figure 27 shows the collapsed water level in the core.

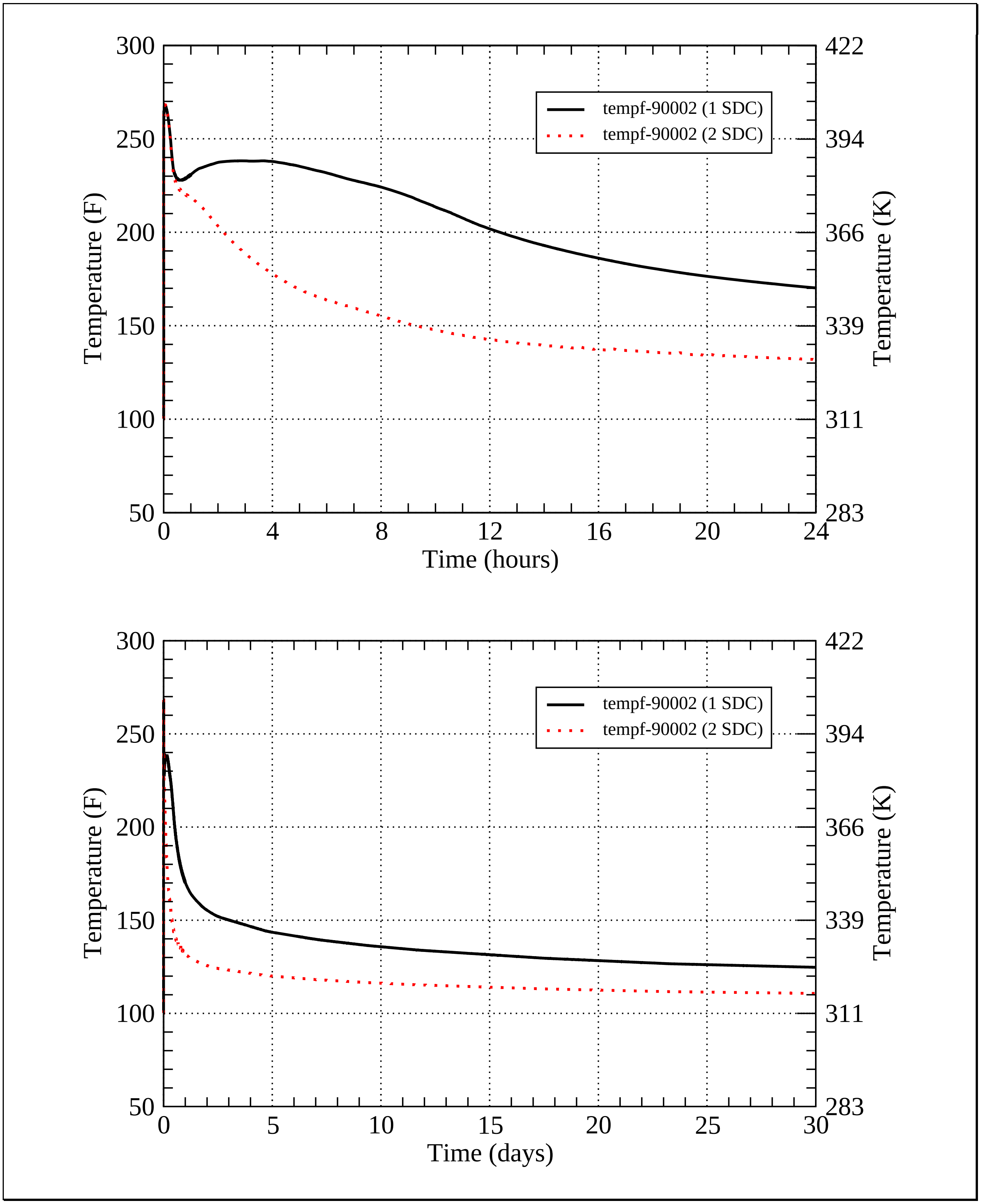

Figure 6: *Sump Fluid Temperature - Large Break LOCA (Hot Leg)*

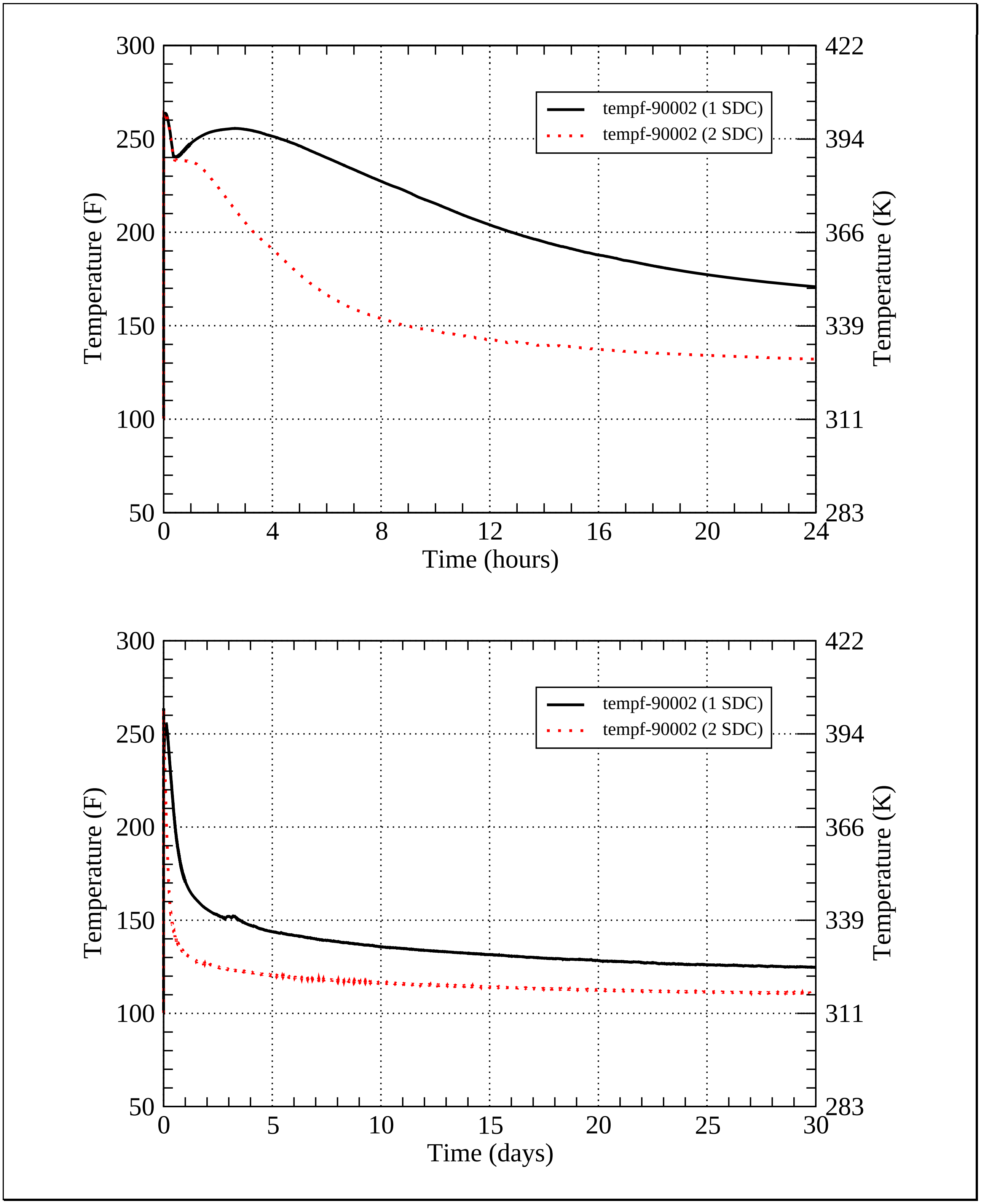

Figure 7: *Sump Fluid Temperature - Large Break LOCA (Cold Leg)*

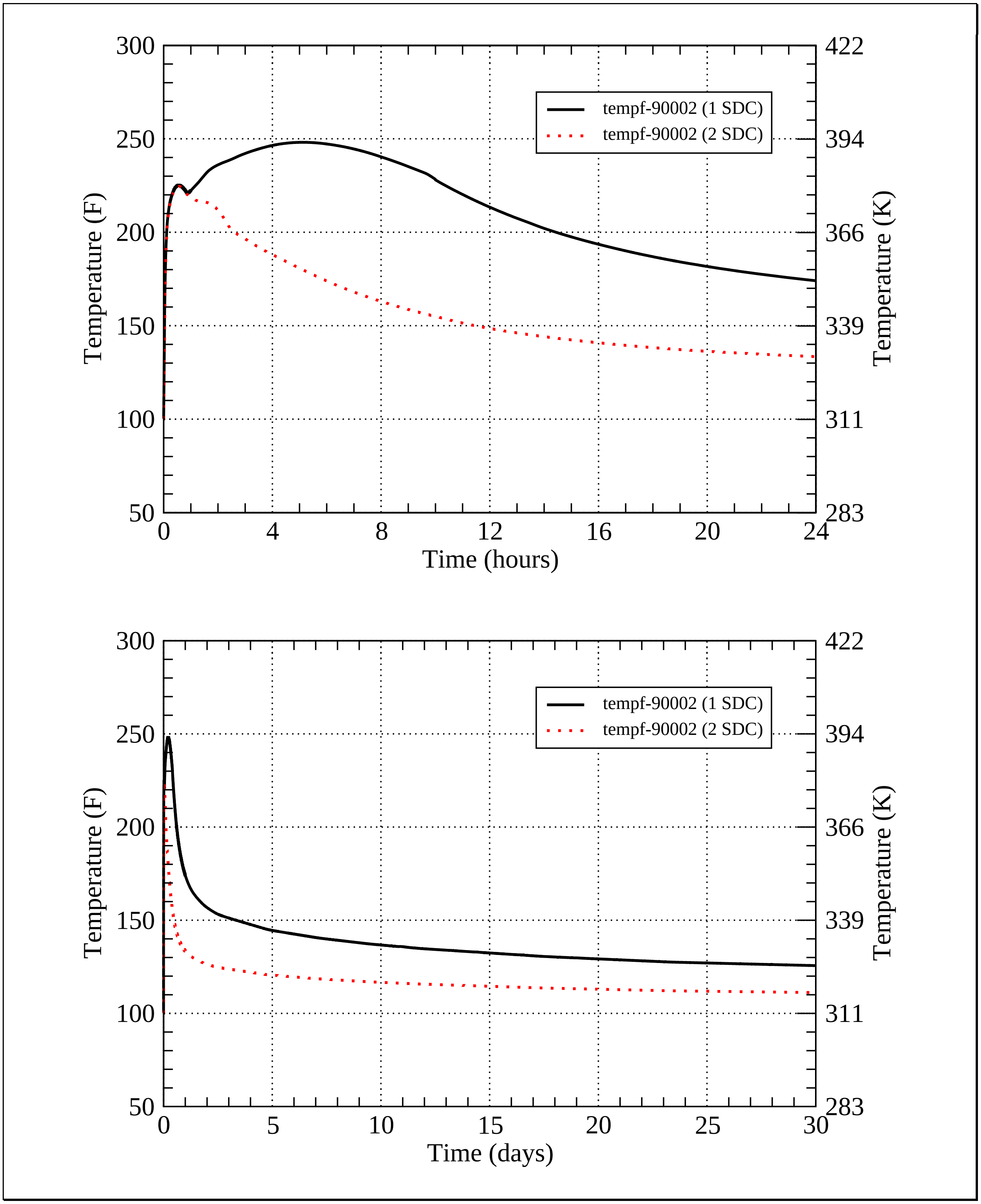

Figure 8: *Sump Fluid Temperature - Small Break LOCA (Hot Leg)*

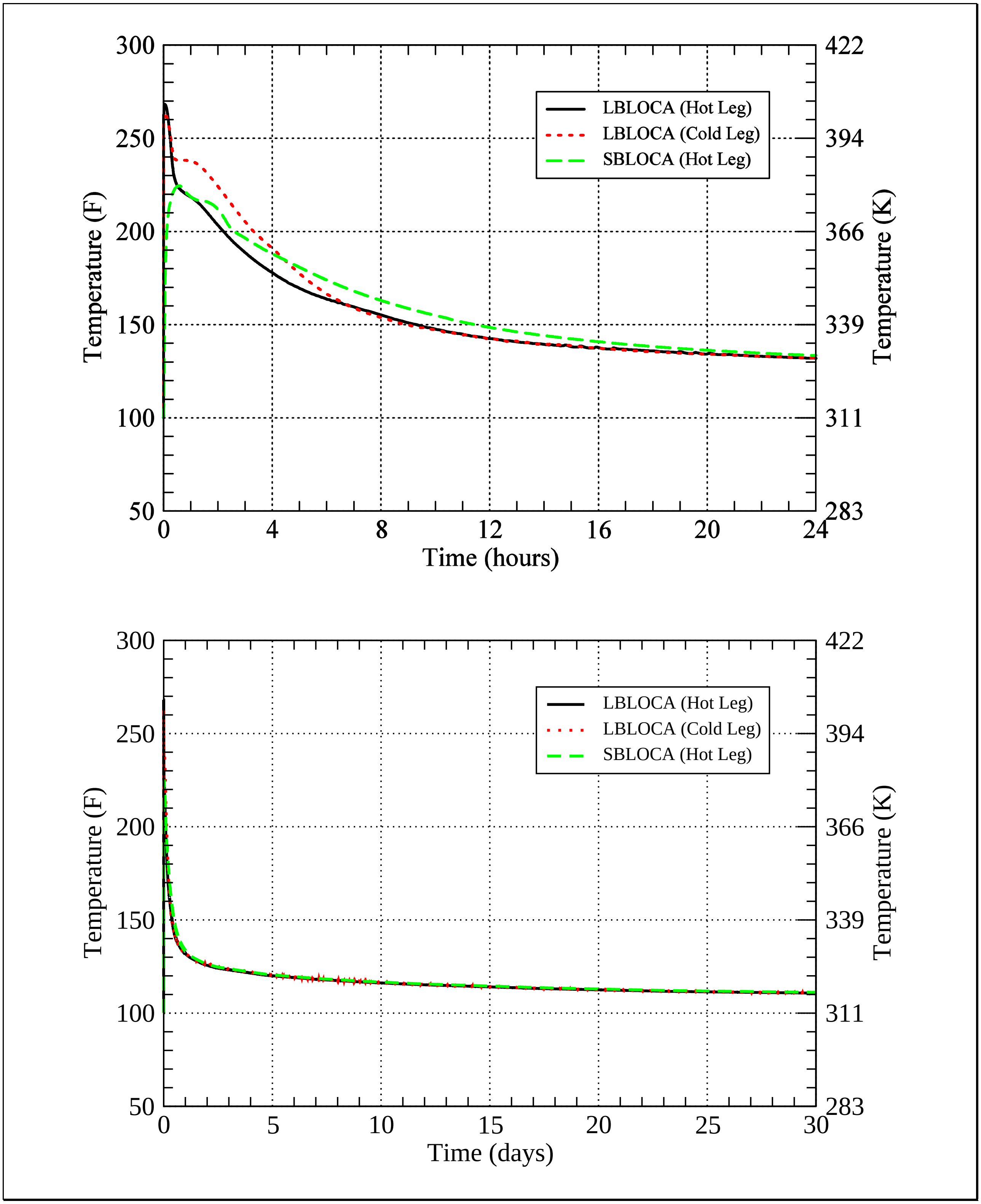

Figure 9: *Sump Fluid Temperature Comparison for Cases with 2 SDC Heat Exchangers Operating*

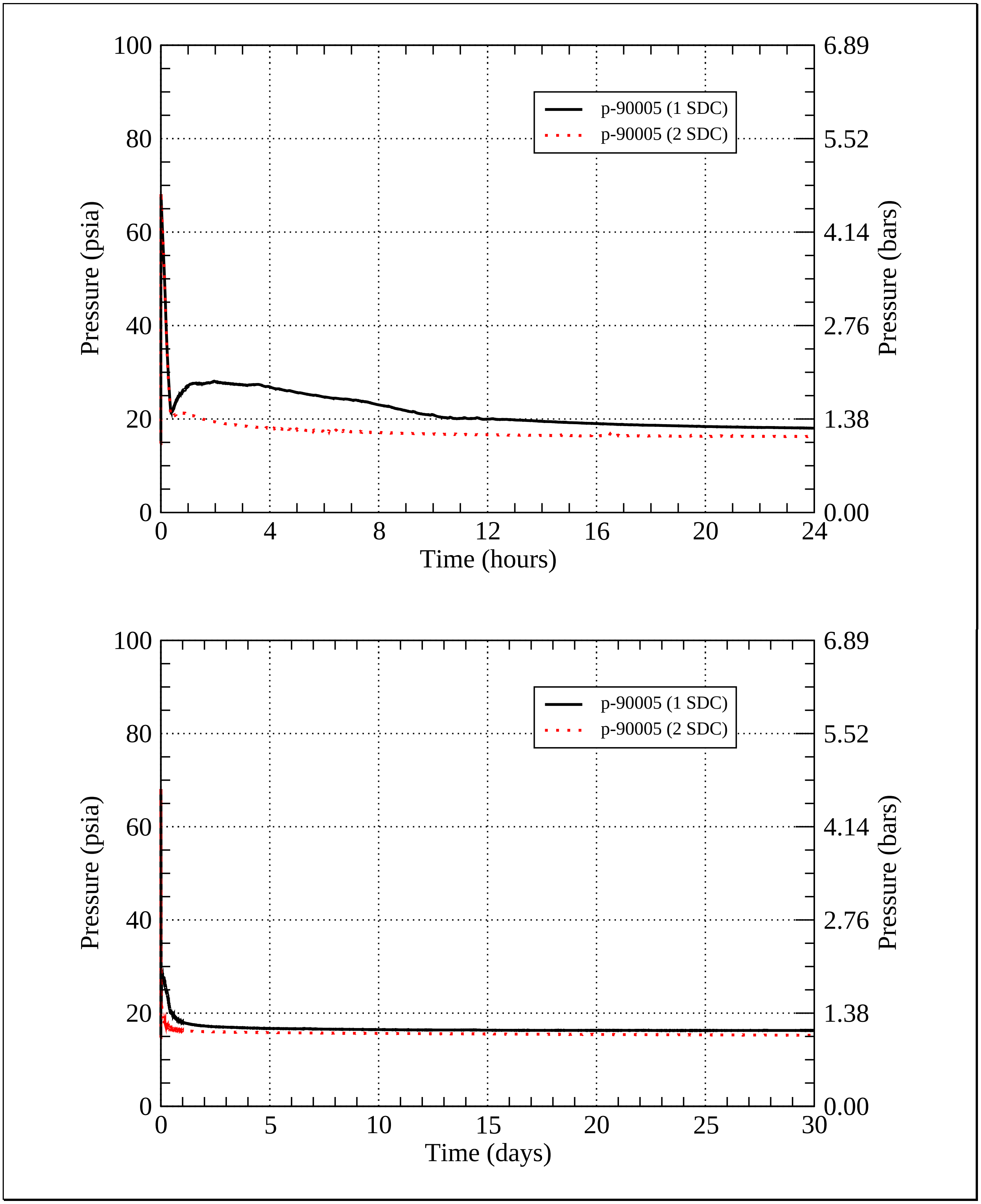

Figure 10: *Containment Pressure - Large Break LOCA (Hot Leg)*

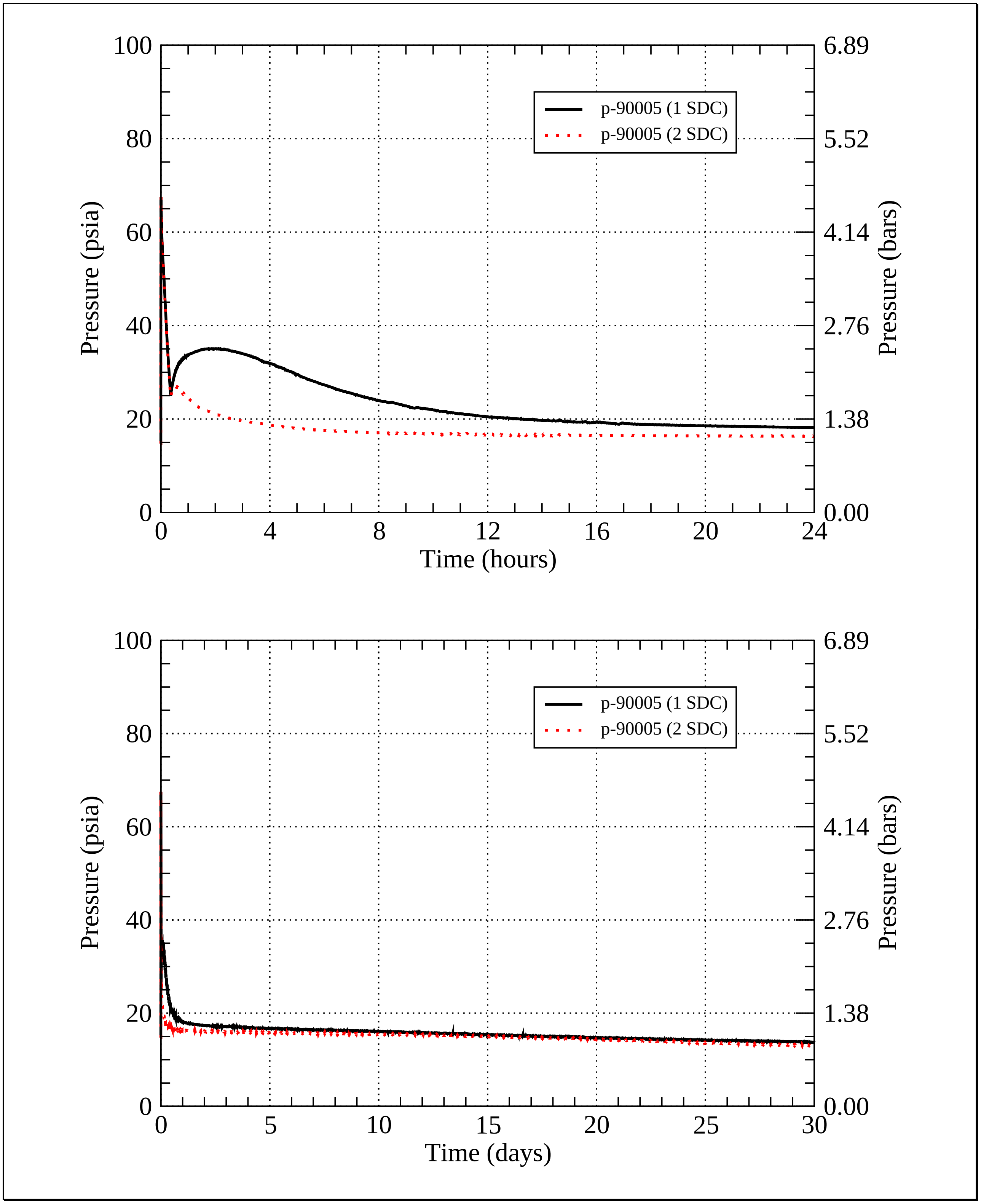

Figure 11: *Containment Pressure - Large Break LOCA (Cold Leg)*

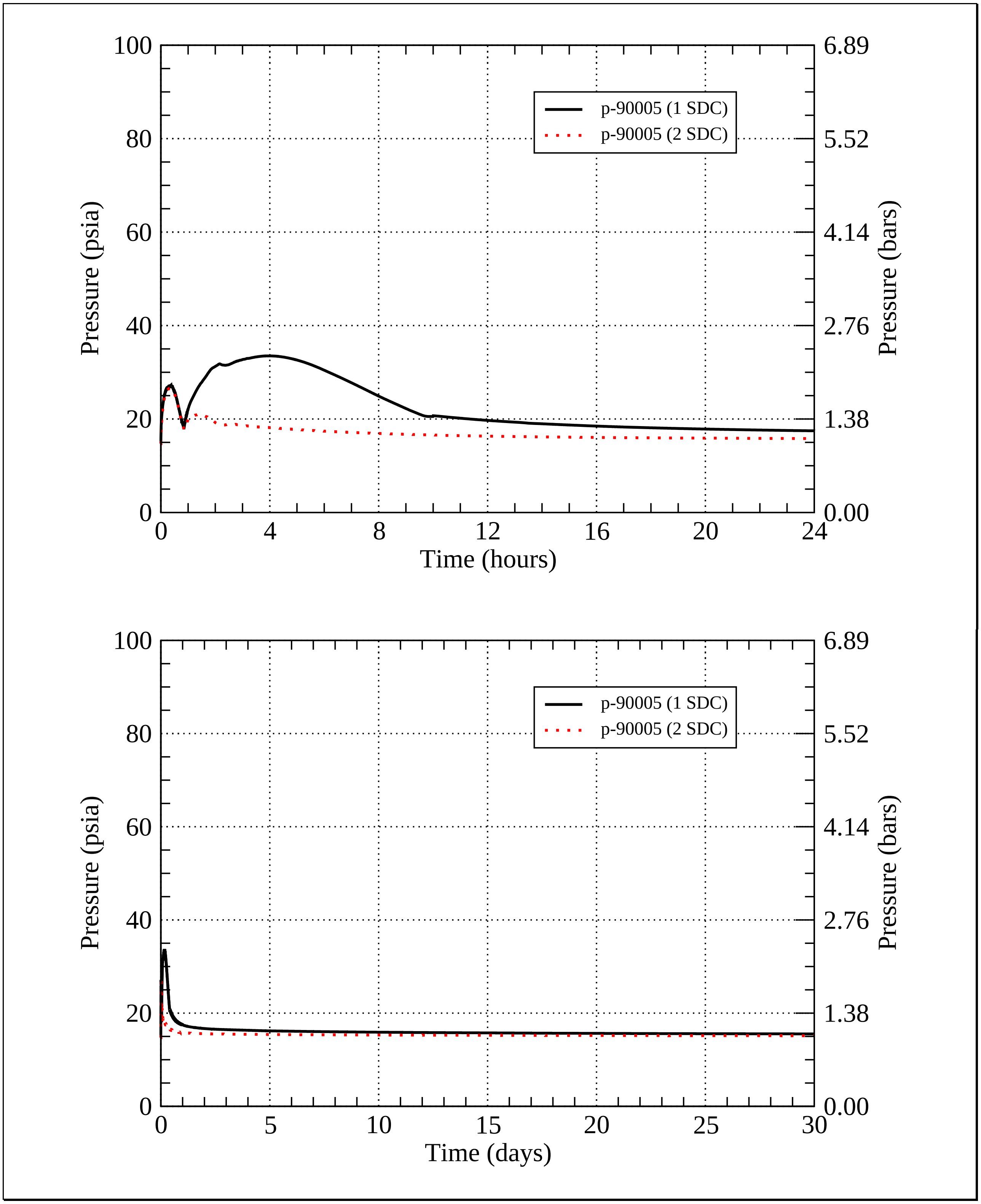

Figure 12: *Containment Pressure - Small Break LOCA (Hot Leg)*

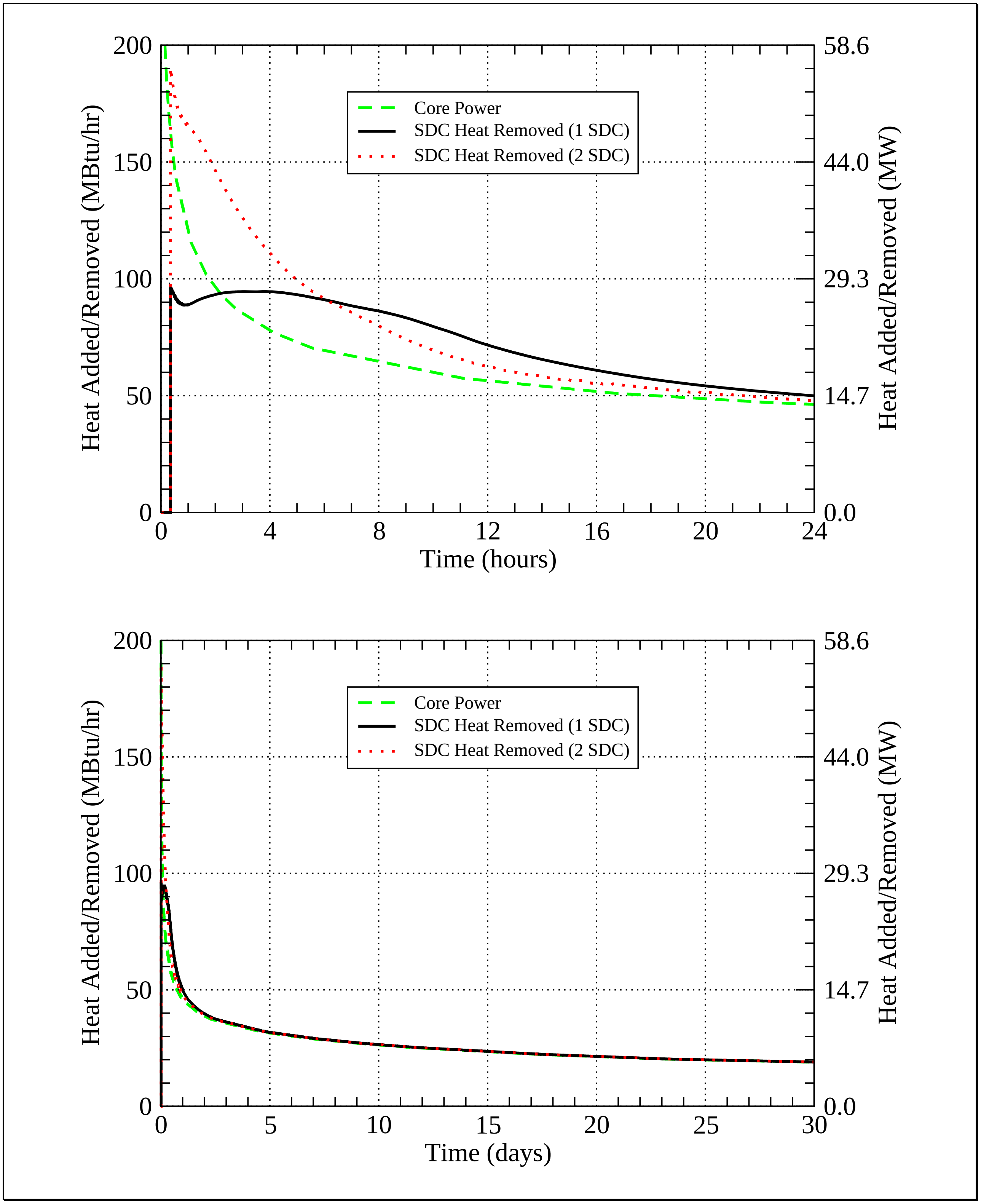

Figure 13: *Heat Added/Removed - Large Break LOCA (Hot Leg)*

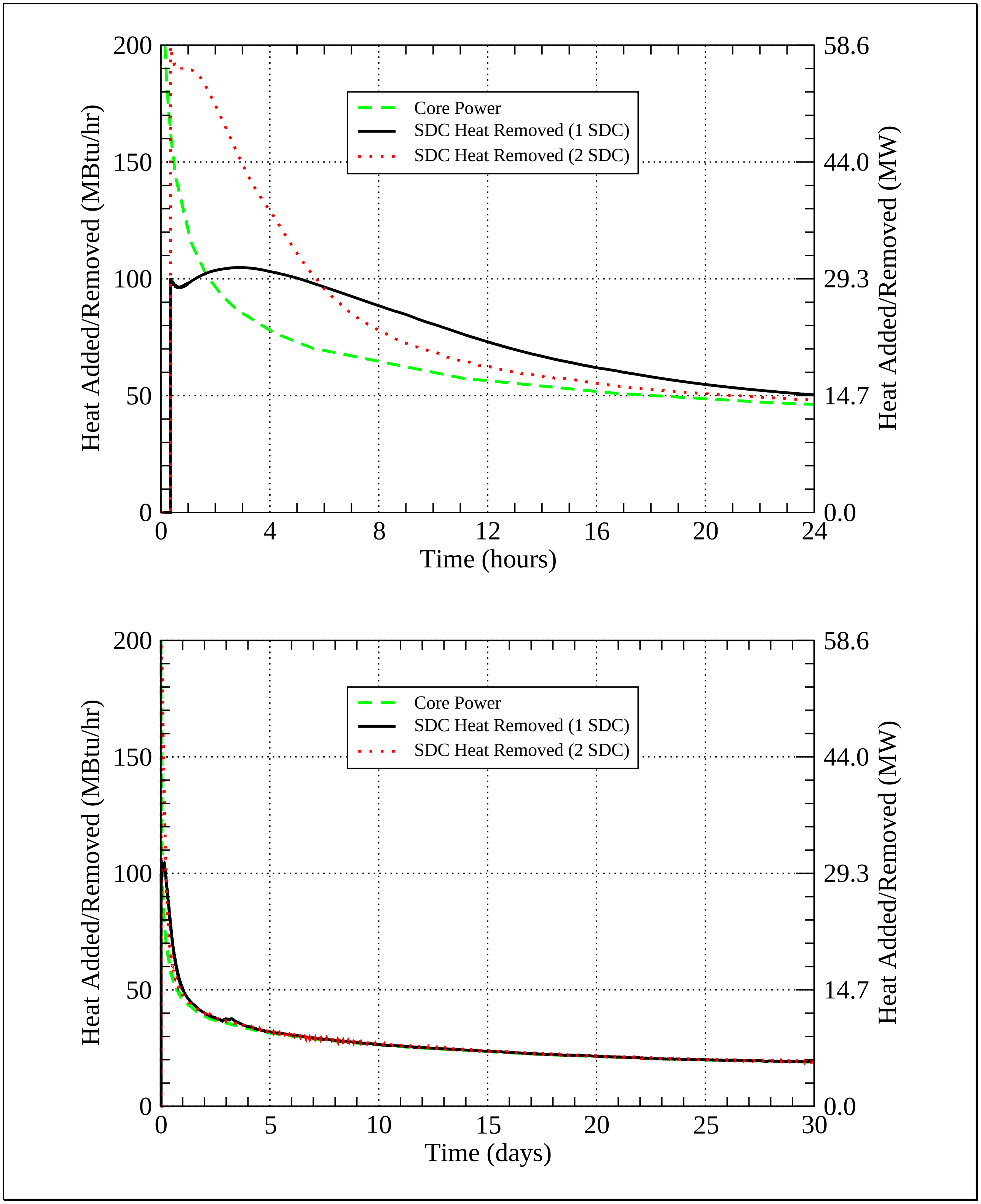

Figure 14: *Heat Added/Removed - Large Break LOCA (Cold Leg)*

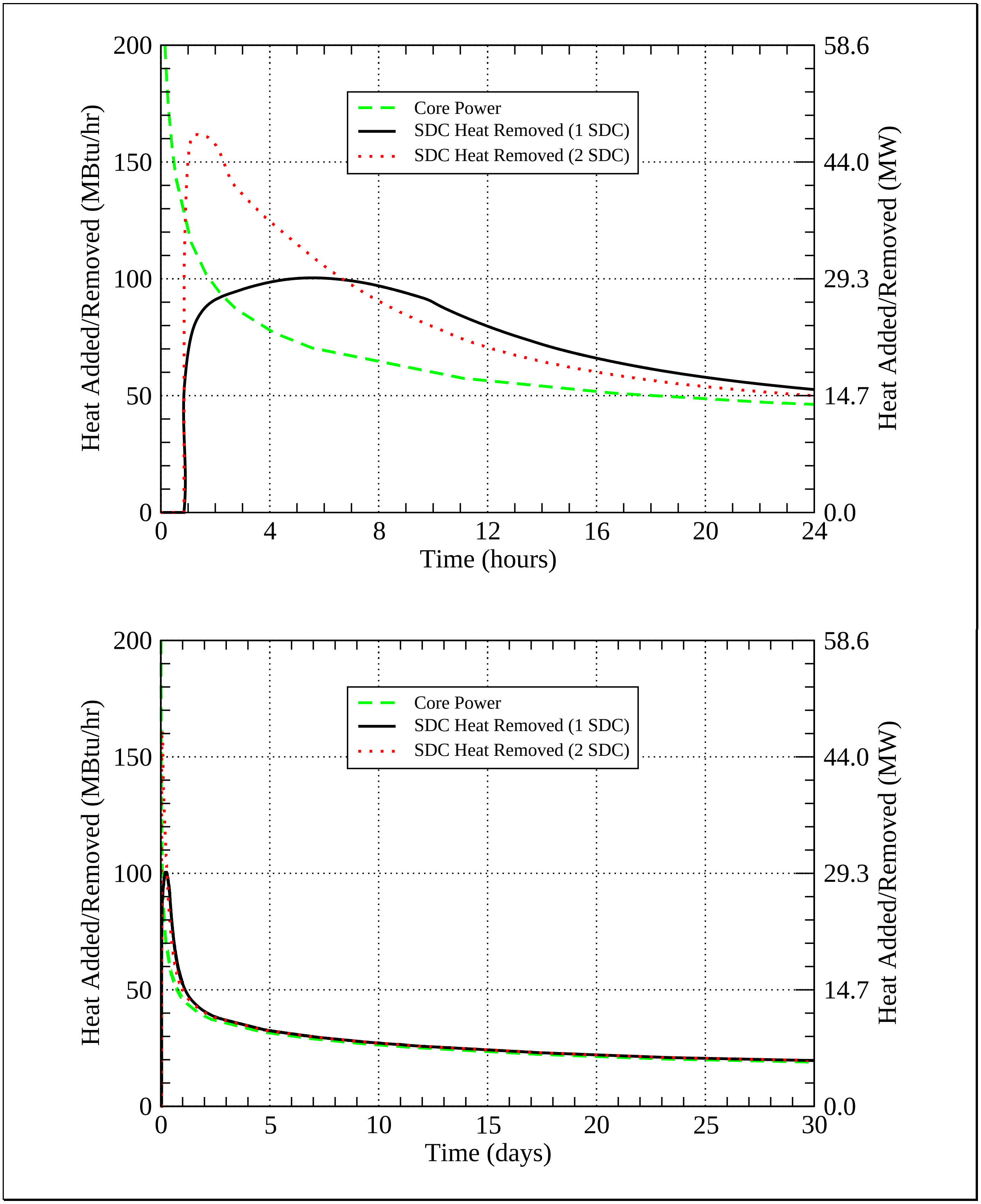

Figure 15: *Heat Added/Removed - Small Break LOCA (Hot Leg)*

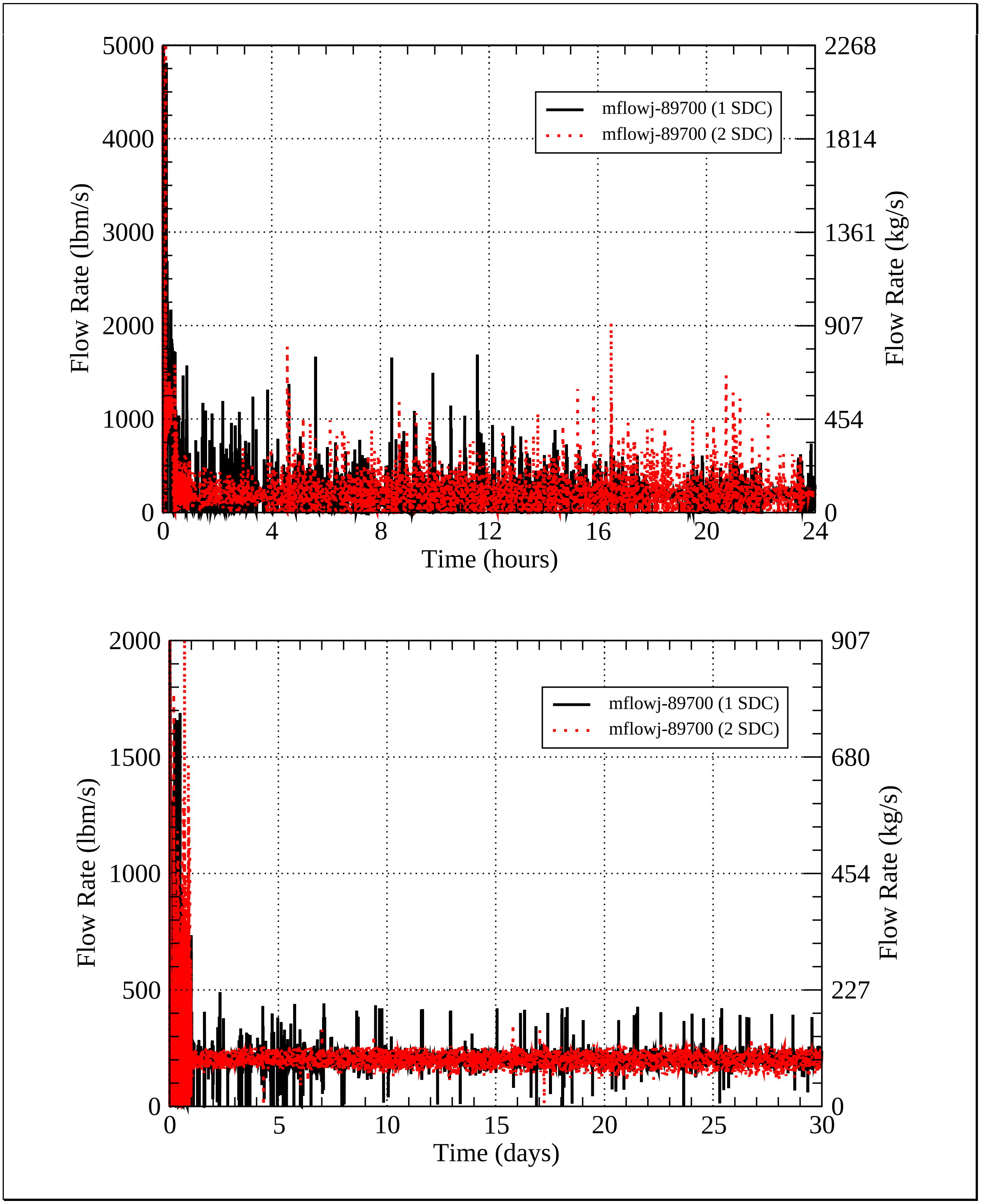

Figure 16: *Break Flow - Large Break LOCA (Hot Leg)*

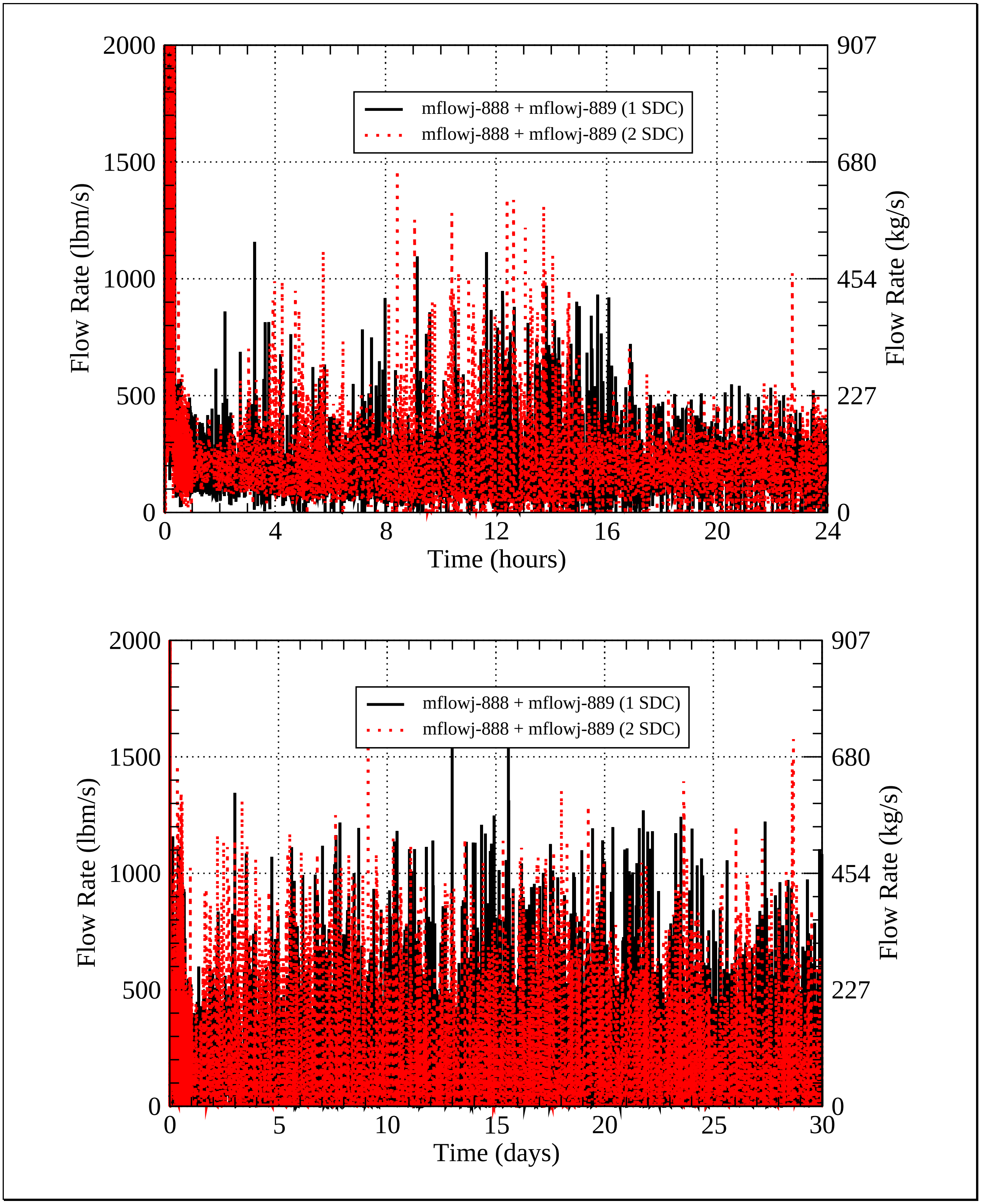

Figure 17: *Break Flow - Large Break LOCA (Cold Leg)*

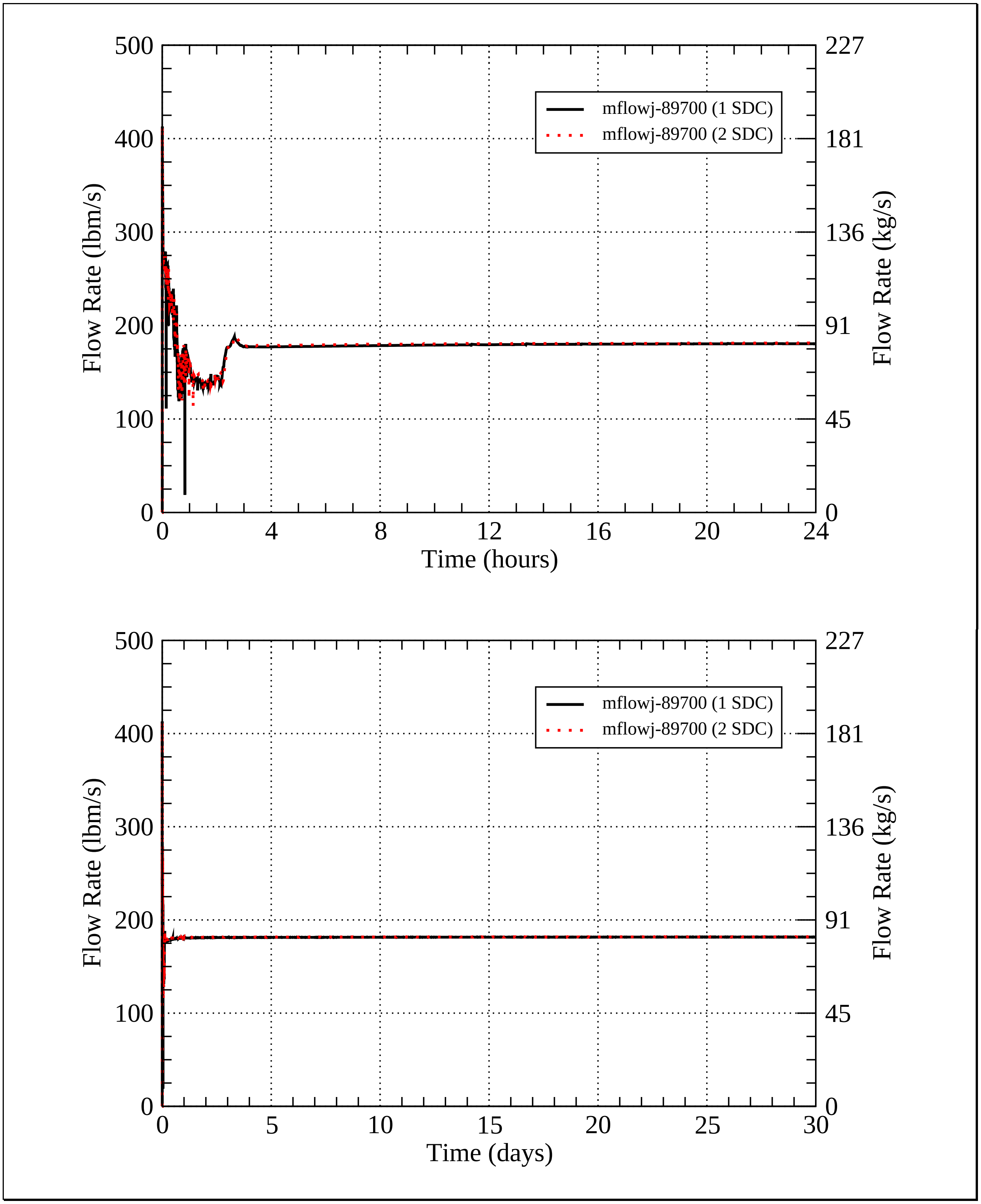

Figure 18: *Break Flow - Small Break LOCA (Hot Leg)*

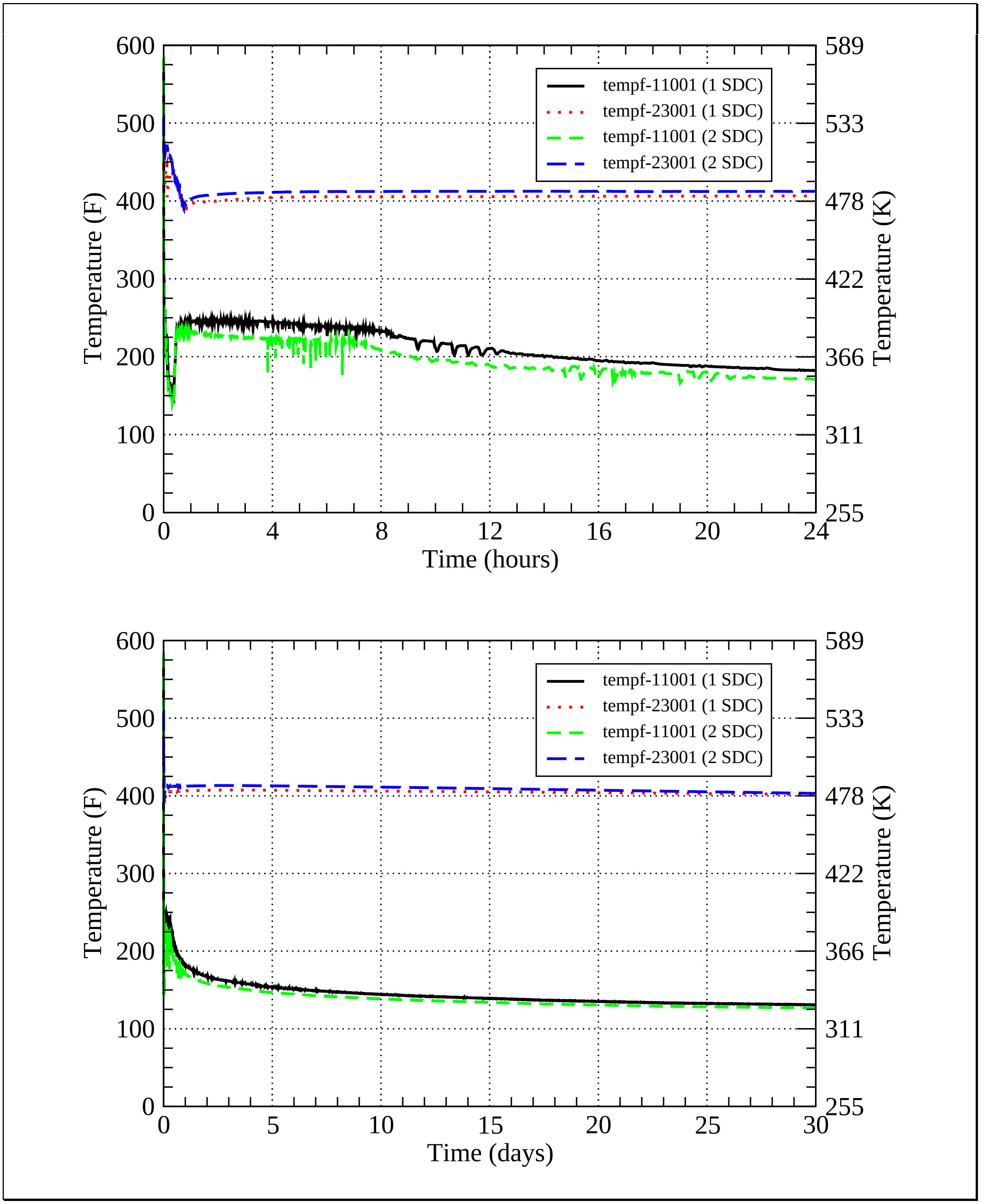

Figure 19: *System Temperatures - Large Break LOCA (Hot Leg)*

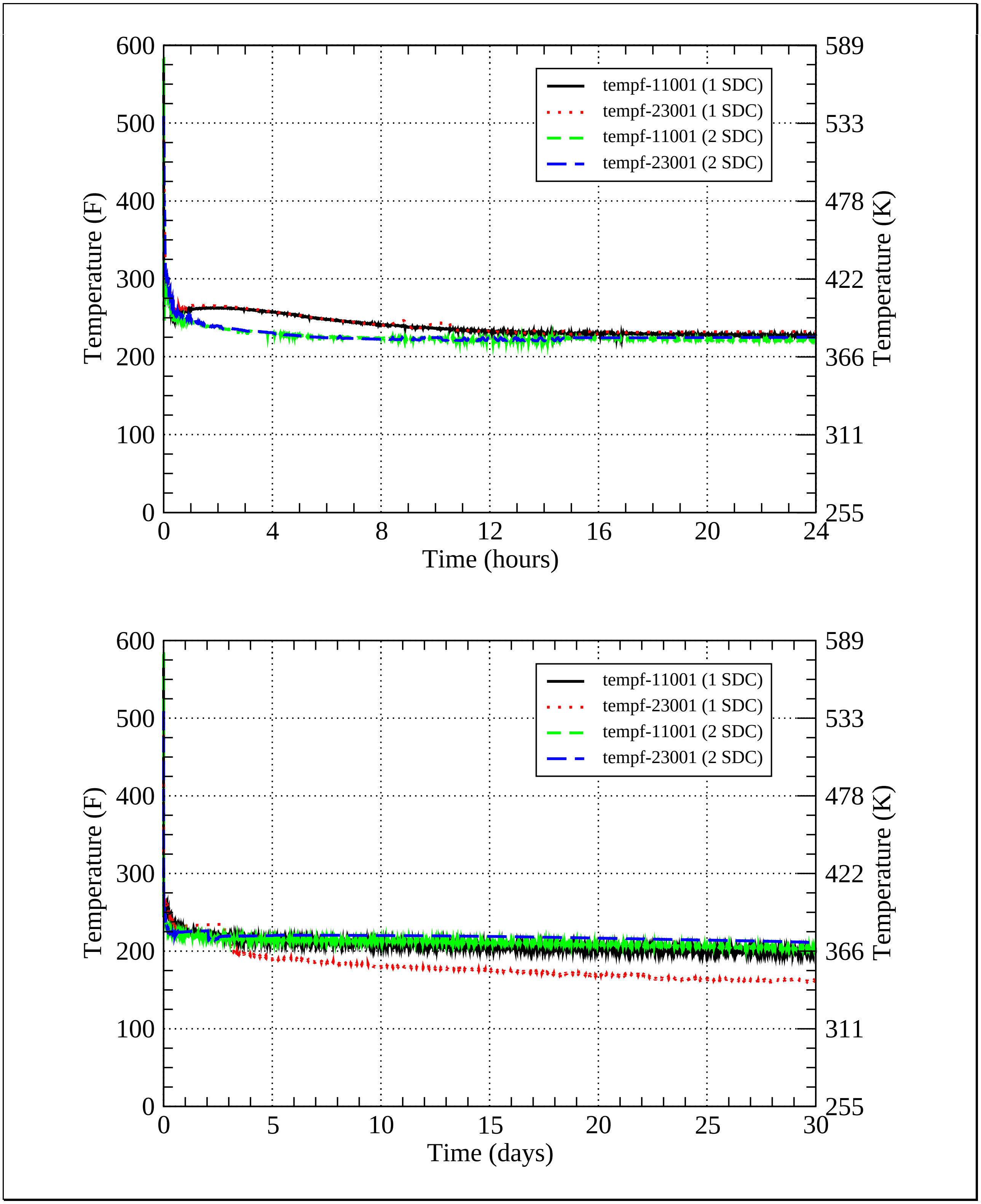

Figure 20: *System Temperatures - Large Break LOCA (Cold Leg)*

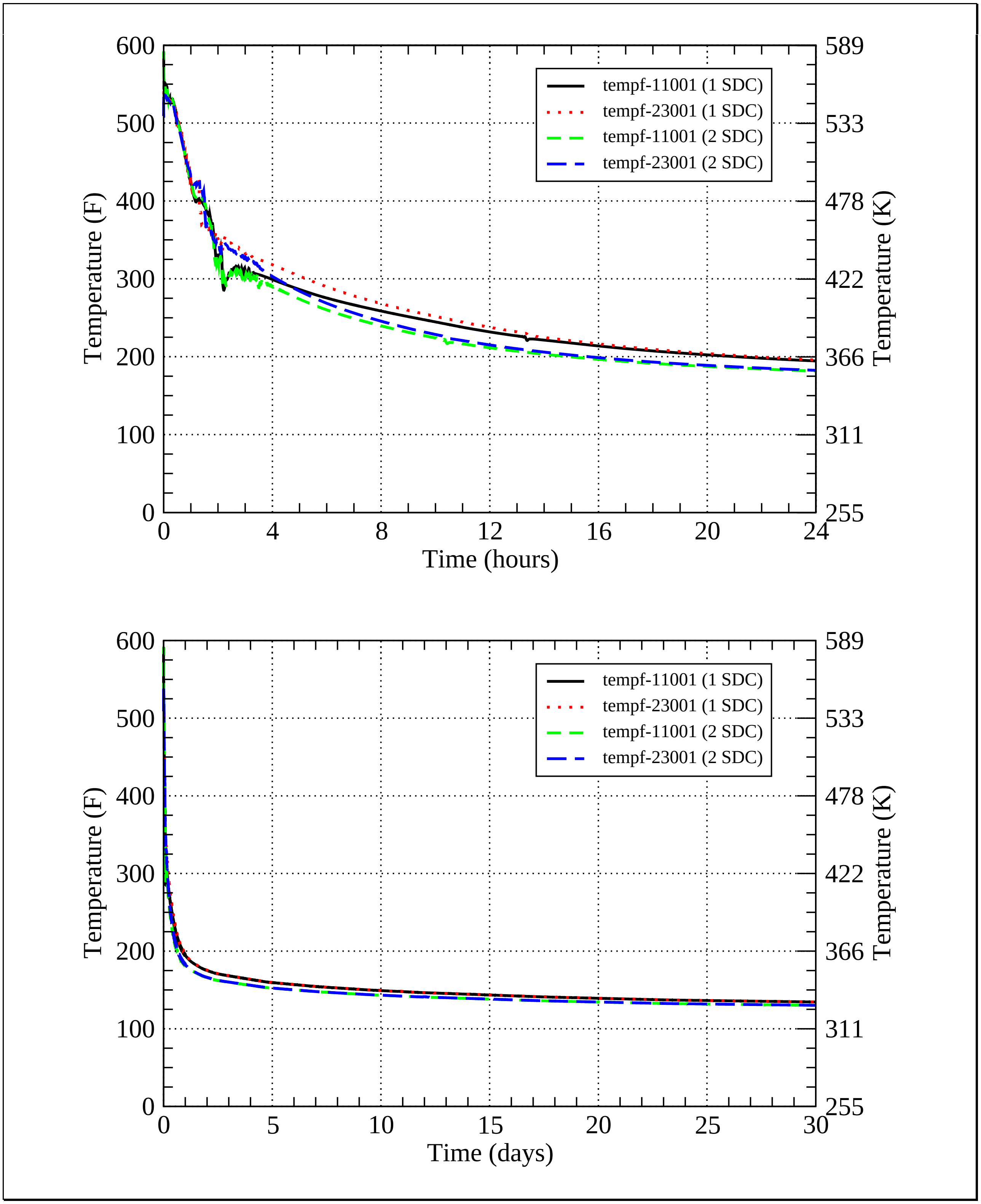

Figure 21: *System Temperatures - Small Break LOCA (Hot Leg)*

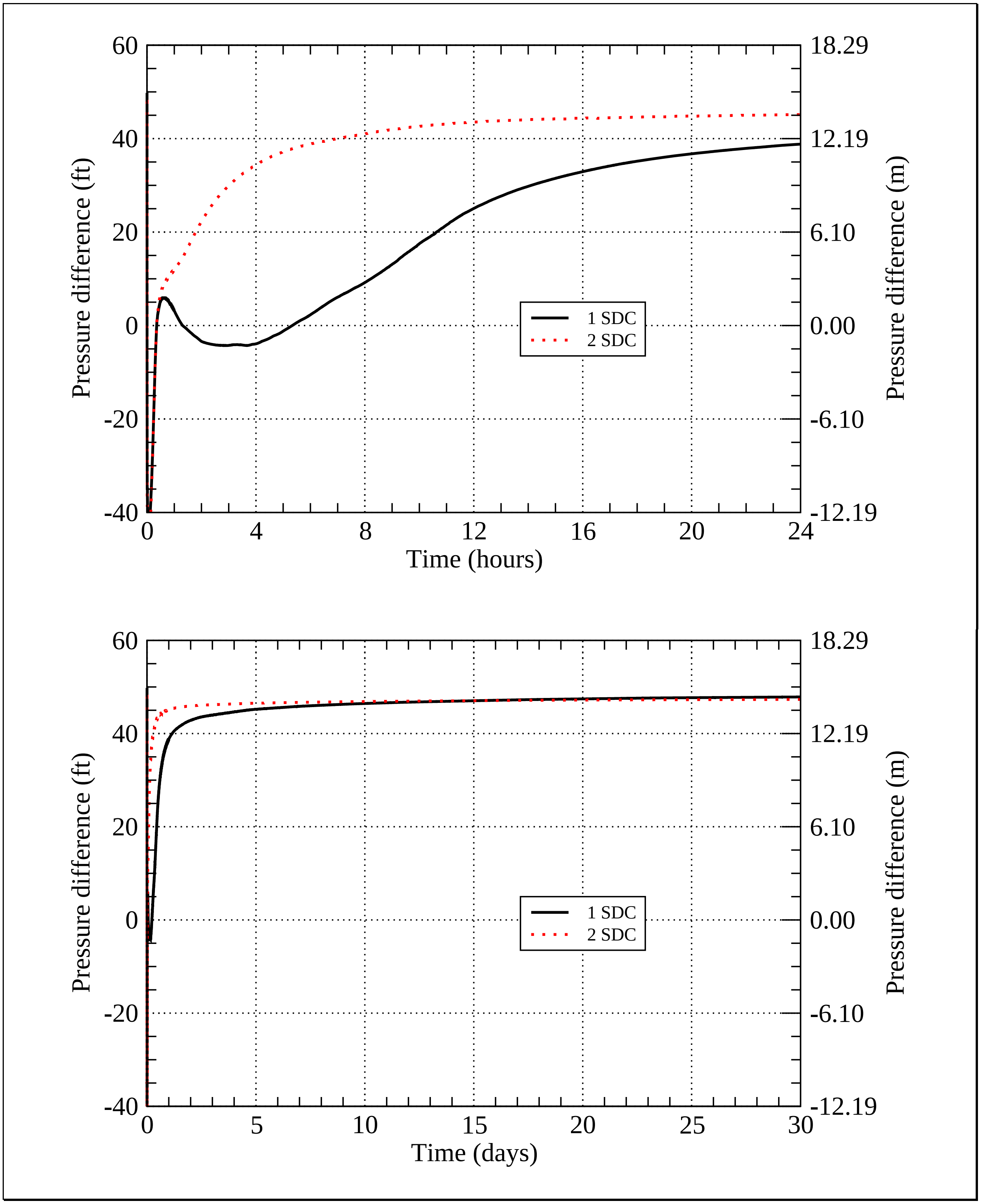

Figure 22: *Normalized $NPSH_{available}$ - Large Break LOCA (Hot Leg)*

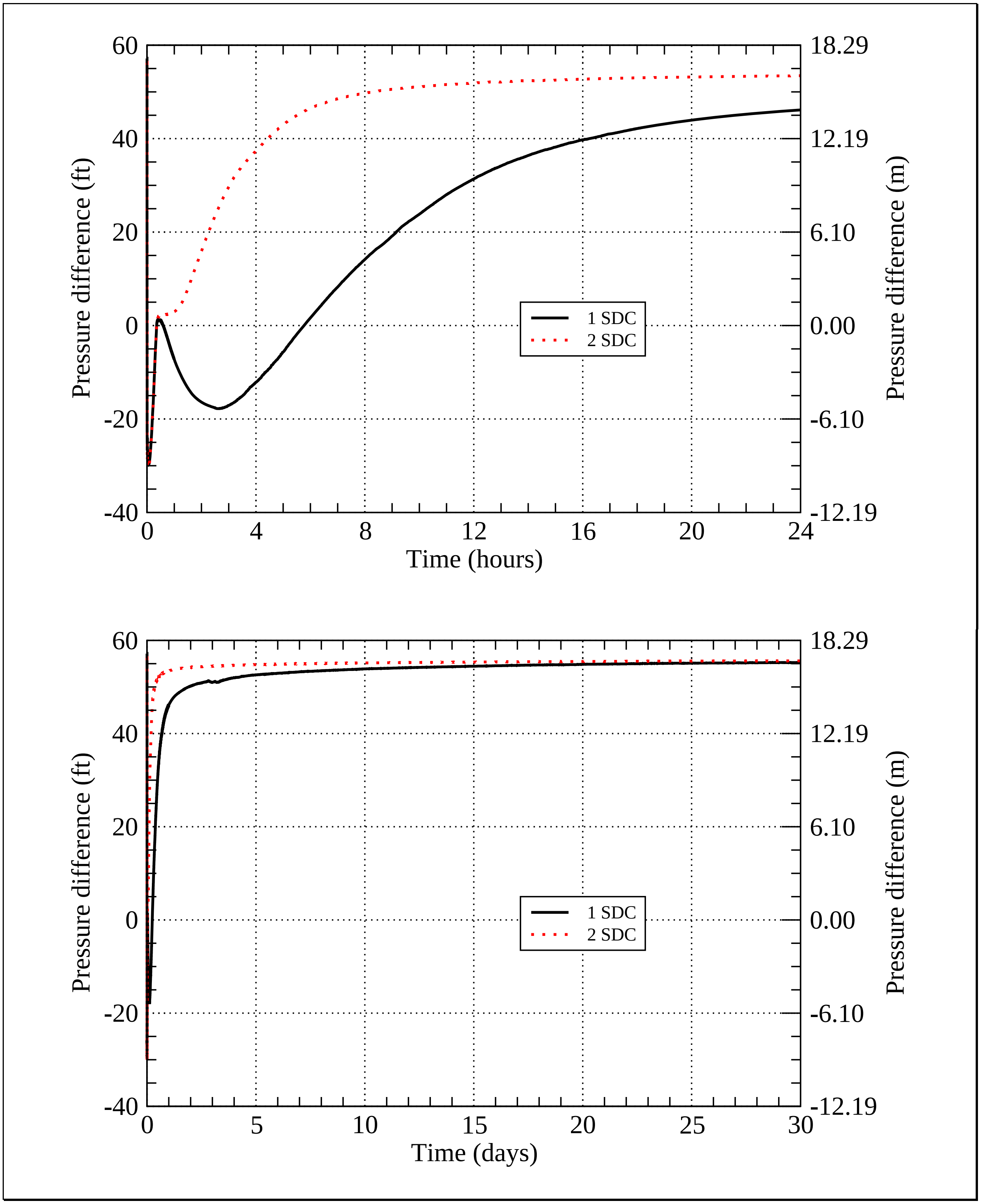

Figure 23: *Normalized $NPSH_{available}$ - Large Break LOCA (Cold Leg)*

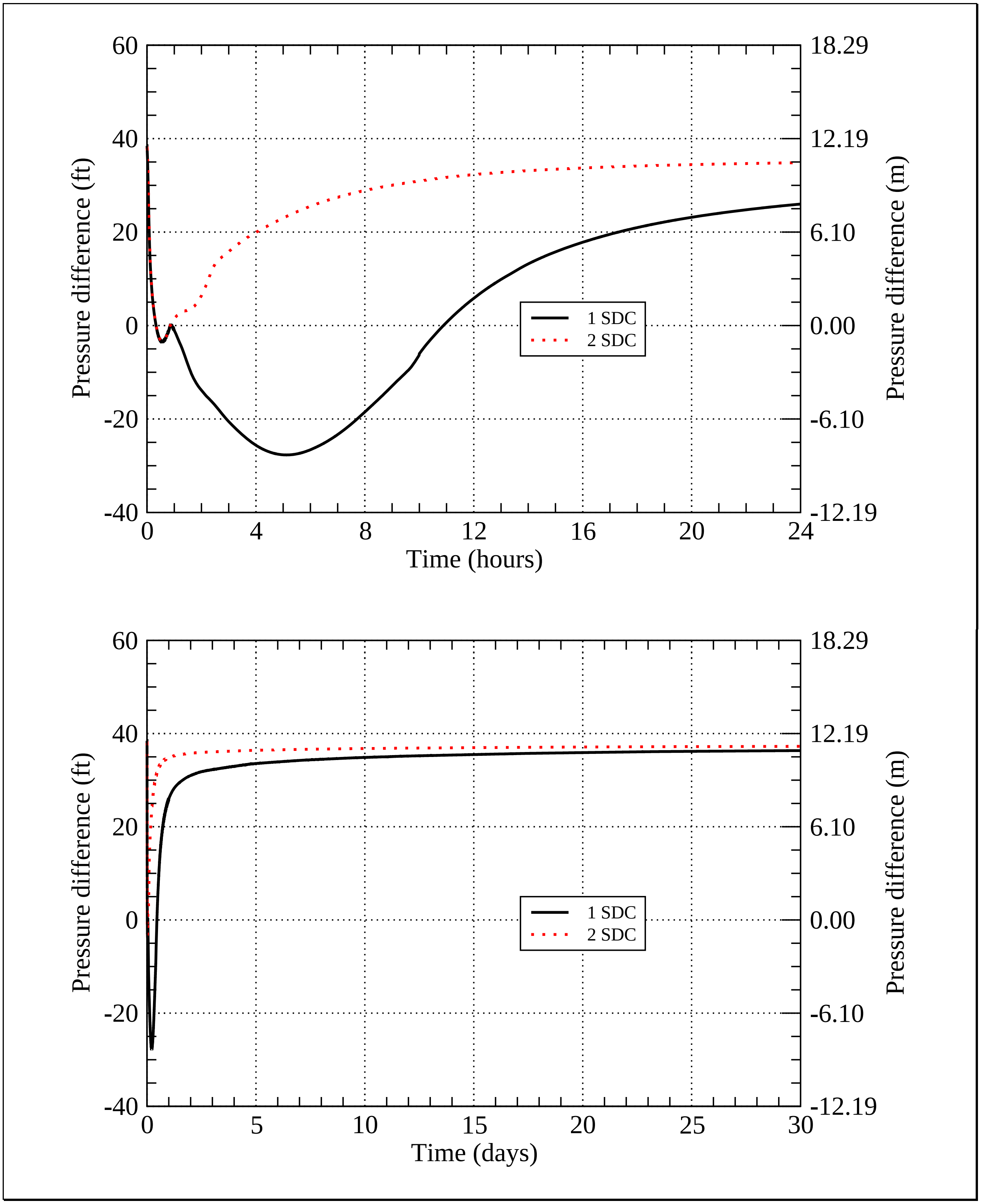

Figure 24: *Normalized NPSH$_{available}$ - Small Break LOCA (Hot Leg)*

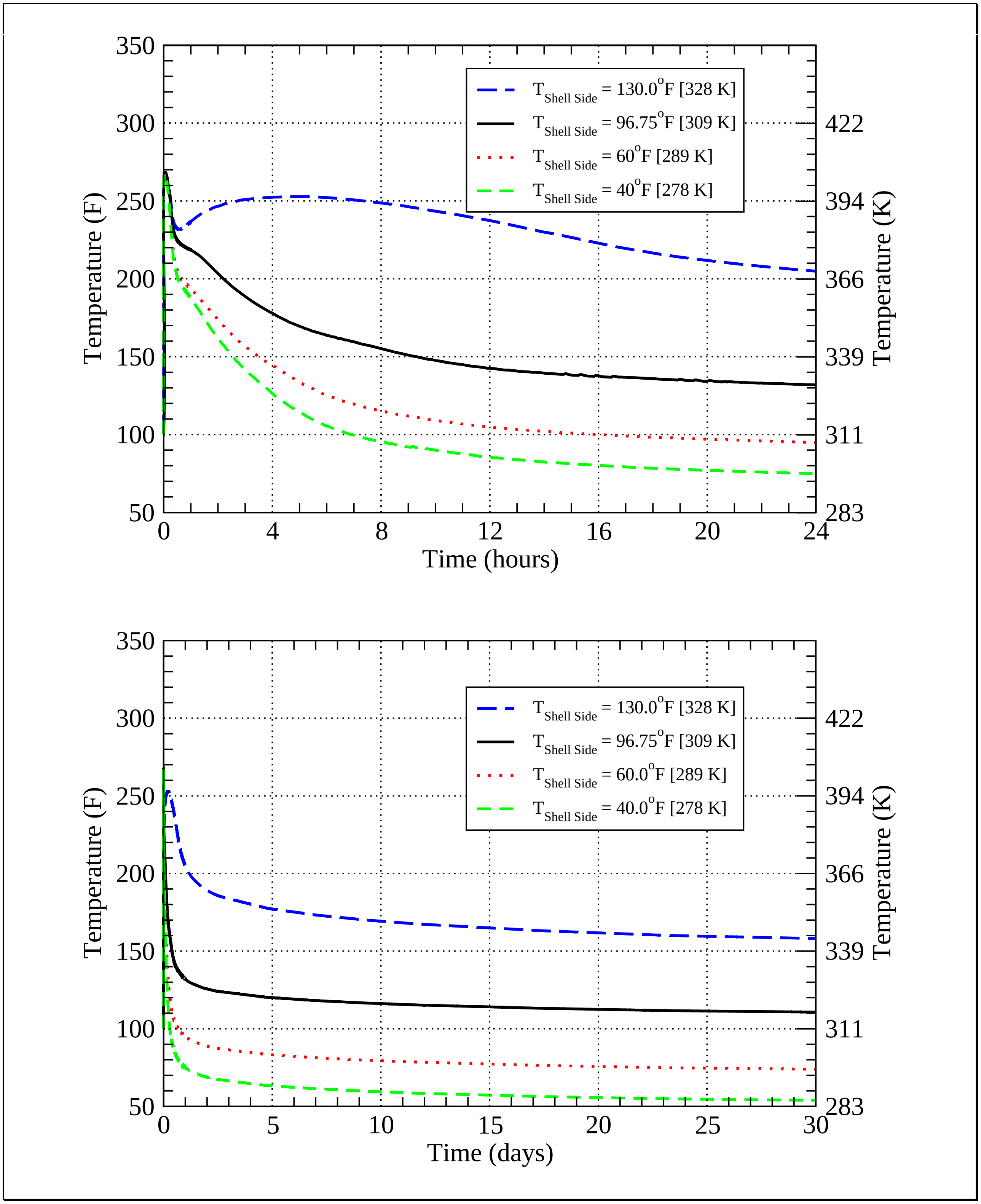

Figure 25: *Sump Fluid Temperature for Large Hot Leg Breaks w/Varied SDC Heat Exchanger Inlet Temperature*

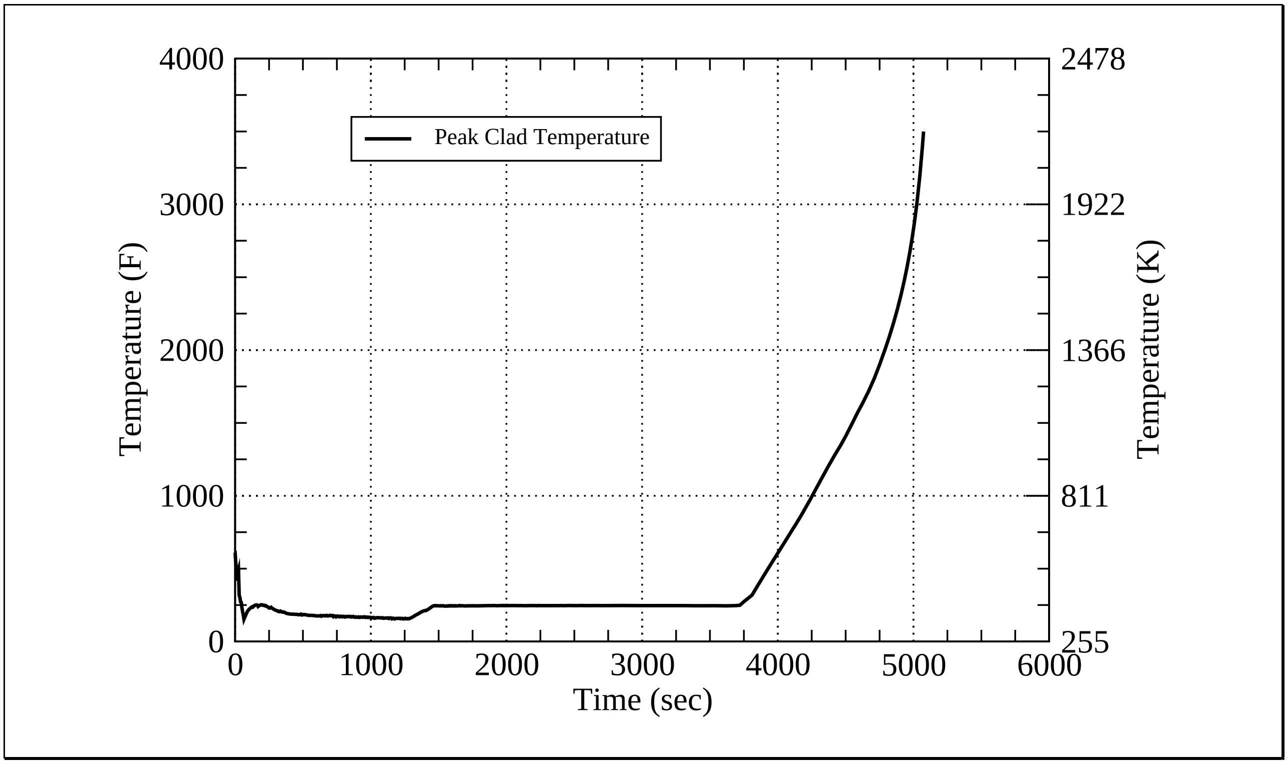

Figure 26: *Peak Clad Temperature With Completely Blocked Sump Screens*

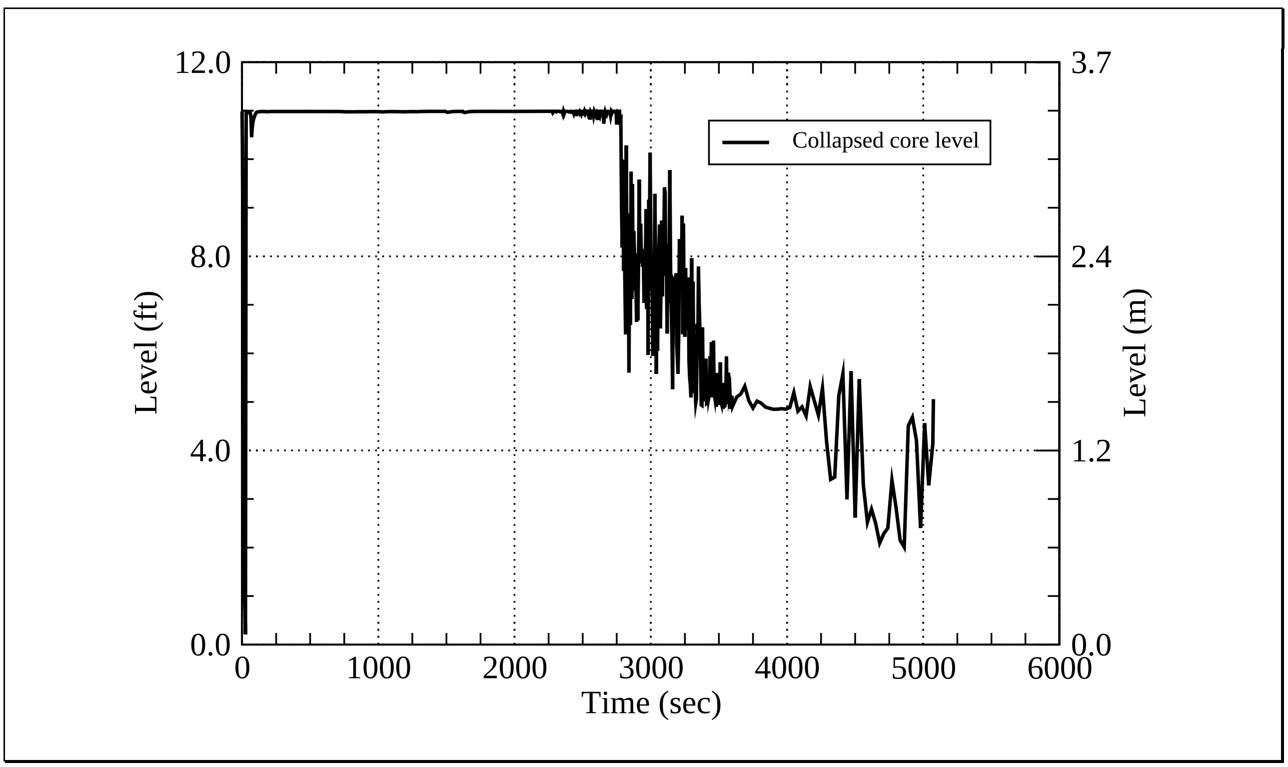

Figure 27: *Collapsed Core Water Level With Completely Blocked Sump Screens*

4.0 Calculation of NPSH and Residence times

One parameter of interest is the residence time in the system. This is the time the fluid takes to go from one point through the system and back to the starting point. In this case, it includes two separate flow loops, both starting at the bottom of the sump. The first is from the sump to the HPI pumps, to the cold legs, to the downcomer, to the lower plenum, up the core, to the upper plenum, to the hot leg, through the break and finally back to the sump. The second loop is from the sump to the RHR pump, to the shutdown cooling heat exchanger, to the containment spray lines to the top of containment, and back down containment to the sump. The RELAP5 model has detailed information for the majority of the first loop, but limited information on the second. Residence times are estimated when they can not be directly computed with RELAP5 results. Detailed information on the ECCS and containment spray piping dimensions was not available for the sample plant, therefore, information from a different sample plant was used to obtain pipe sizes. However, it should be noted that lengths were not provided and were estimated. The calculation performed to determine residence times is assumed to be an order of magnitude calculation, therefore, the estimation of ECCS piping lengths is acceptable.

Another important parameter for ECCS operation is the NPSH margin. To provide a general idea of the actual amount of subcooling of the containment sump pool water that exists in the long term, a sample calculation using a mixture of plant-specific data and the RELAP5 results described above was performed. The calculation simulates a period of 30 days, which is generally considered to be the mission time for the containment sump recirculation function.

4.1 Residence Time

The residence times were computed using the large hot leg break case with one operating shutdown cooling heat exchanger. The residence time for each section is computed as flow length (ft) divided by fluid velocity (ft/s). The residence times were computed at three times during the 30 day transient; ten minutes after switchover to sump recirculation mode, one day and 30 days. Results from these calculations are provided in Tables 7 and 8 and can provide insight in understanding timing aspects related to the review of licensees' chemical effects evaluations.

Table 7: *Computed Residence Times from the Sump through the Vessel back to the Sump*

Component	Residence time					
	1,870 s		1 day		30 days	
	Time	Temp	Time	Temp	Time	Temp
Sump to HPI pump(1)	50 s	234˚F	50 s	170˚F	50 s	125˚F
HPI pump to cold leg(2)	10 s	234˚F	10 s	170˚F	10 s	125˚F
Cold leg (from HPI injection to vessel inlet)	90 s	137˚F	60 s	118˚F	75 s	105˚F
Downcomer	110 s	155˚F	135 s	119˚F	180 s	105˚F
Lower plenum	80 s	156˚F	160 s	119˚F	215 s	105˚F
Core	80 s	209˚F	115 s	154˚F	155 s	119˚F
Upper Plenum to break	140 s	238˚F	150 s	182˚F	210 s	131˚F
Break to sump(3)	5 s	238˚F	5 s	170˚F	5 s	125˚F
Sump	12,205 s	234˚F	11,860 s	170˚F	11,640 s	125˚F

(1) - Estimated; 24" diameter pipe, 25 ft in length plus 6" diameter pipe, 15 ft in length (in series)

(2) - Estimated; 6" diameter pipe, 60 ft in length plus 3" diameter pipe, 75 ft in length (in series)

(3) - Estimated; break height is approximately 47 ft above sump water surface (time < 5 sec)

Table 8: *Computed Residence Times from the Sump through the Containment Sprays back to the Sump*

Component	Residence time					
	1,870 s		1 day		30 days	
	Time	Temp	Time	Temp	Time	Temp
Sump to containment spray pump(1)	20 s	234˚F	20 s	170˚F	20 s	125˚F
Containment spray pump to SDC HX(2)	5 s	234˚F	5 s	170˚F	5 s	125˚F
SDC HX to top of containment(3)	15 s	136˚F	15 s	118˚F	15 s	105˚F
Top of containment to sump(4)	5 s	136˚F	5 s	118˚F	5 s	105˚F
Sump(5)	12,205 s	234˚F	11,860 s	170˚F	11,640 s	125˚F

(1) - Estimated; 24" diameter pipe, 25 ft in length

(2) - Estimated; 8" diameter pipe, 15 ft in length plus 10" diameter pipe, 10 ft in length (in series)

(3) - Estimated; 8" diameter pipe, 125 ft in length plus 4" diameter pipe, 60 ft in length (in series)

(4) - Estimated; top of containment is approximately 180 ft above sump water surface (time < 5 sec)

(5) - Same as computed in the primary loop

4.2 Net Positive Suction Head

To avoid cavitation in centrifugal pumps, the pressure of the fluid at all points within the pump must remain above saturation pressure. Net positive suction head is used as a measure to determine if the pressure of the liquid being pumped is adequate to avoid cavitation. The net positive suction head available is the difference between the pressure at the suction of the pump and the saturation pressure of the liquid being pumped. The net positive suction head required is the minimum net positive suction head determined necessary by test to ensure proper pump operation. The accepted definition for NPSH required is the amount of suction head, over vapor pressure, required to prevent more than 3% loss in total head of the first stage of the pump at a specific capacity.

For acceptable pump operation, it is desirable that the net positive suction head available be greater than or equal to the net positive suction head required.

NPSH margin can be calculated as:

$$NPSH_{margin} = NPSH_{available} - NPSH_{required} \qquad \text{(Equation 1)}$$

where $NPSH_{available}$ is defined as:

$$NPSH_{available} = H_a - H_{vapor} + H_{static} - H_{friction} \qquad \text{(Equation 2)}$$

As the licensee's licensing-basis methodology assumes that the containment pressure (H_a) is equal to the saturated vapor pressure of the sump fluid (H_{vapor}), the available NPSH calculated by the licensee (denoted $NPSH_{available, SRP}$, since the assumption that $H_a = H_{vapor}$ is derived from Section 6.2.2 of the Standard Review Plan (SRP)) is just the difference between the static head of water above the pump suction (H_{static}) and the friction losses in the suction piping ($H_{friction}$):

$$NPSH_{available, SRP} = H_{static} - H_{friction} \qquad \text{(Equation 3)}$$

Then the NPSH margin, consistent with SRP Section 6.2.2, can be defined as:

$$NPSH_{margin, SRP} = NPSH_{available, SRP} - NPSH_{required} \qquad \text{(Equation 4)}$$

To include modeling of the effect of subcooling from containment overpressure, values for H_a and H_{vapor} were computed from the RELAP5 results.

The containment pressure head (H_a) was calculated using the containment pressure from volume 900-02, which was considered to best represent the pressure existing over the surface of the containment pool. Pressure (psi) may be converted to head (ft) using the following equation:

$$\text{Head (ft)} = \text{Pressure (psi)} * 2.31 / \text{Specific Gravity} \qquad \text{(Equation 5)}$$

The saturated vapor pressure of the sump fluid (H_{vapor}) can also converted to a head term using Equation 5 above.

Then the containment overpressure head ($H_{overpressure}$) can be defined as follows:

$$H_{overpressure} = H_a - H_{vapor} \qquad \text{(Equation 6)}$$

To find the $NPSH_{margin}$ that includes containment overpressure head, the desired quantity, the following equation is used:

$$NPSH_{margin} = NPSH_{margin, SRP} + H_{overpressure} \qquad \text{(Equation 7)}$$

The plant-specific data used was chosen from Case 1ABA M, one of several dozen NPSH cases calculated by the licensee. This case was chosen for a number of reasons, including (1) it was a cold-leg large-break LOCA, (2) it modeled a single operating containment spray pump, (3) it had a small value of $NPSH_{margin, SRP}$ (which emphasizes the contribution of the containment accident pressure head), and (4) it represented a plant condition created by a single failure. Case 1 ABA M was not the most limiting case with respect to NPSH margin (in fact, a failure of a sump suction valve to open is shown to result in a value of $NPSH_{margin, SRP}$ of -10.06 ft prior to manual corrective action being taken). However, the input parameters for the most limiting case were sufficiently dissimilar to the input parameters used in the RELAP5 simulation that it would not be appropriate to combine these two sets of data. Further, the plant conditions and NPSH results associated with the most limiting failure are not considered representative of a typical PWR, and would not be expected to persist through the long-term portion of the calculation.

Despite efforts to match as closely as possible the input parameters of the licensee's calculation to the input parameters of the RELAP5 simulation, certain inconsistencies appear present. Most notably, the licensee assumes that both shutdown cooling heat exchangers are aligned for heat removal for all of the licensee's NPSH cases analyzed, regardless of how many containment spray pumps are operating. The RELAP5 model, for which only two shutdown cooling alignments were run, considered (1) one spray pump and one heat exchanger and (2) two spray pumps and two heat exchangers, neither of which directly corresponds to the assumptions made for Case 1 ABA M. Of further note, a 700 gpm inconsistency seems to exist between the flow rates passing through both the containment spray pumps and shutdown cooling heat exchangers in the RELAP5 model as compared to the licensee's calculations. Specifically, in the RELAP5 model, the flow rate apparently modeled was approximately 1,420 gpm per spray pump/heat exchanger, whereas for all the single pump scenarios modeled by the licensee, the spray pump flows were approximately 2,150 gpm. (The root cause of this apparent discrepancy may have been a lack of specificity between spray pump flow and spray nozzle flow, since, under the conditions modeled, a HPSI pump is drawing approximately 700 gpm from the discharge of the containment spray pumps and injecting directly to the reactor vessel.)

The primary conclusion to be drawn from the above discussion is that this calculation of $NPSH_{margin}$ should be interpreted as a generic sample calculation, rather than a high-fidelity plant-specific analysis. It should also be noted that the significance of the modeling discrepancies mentioned above would gradually diminish over time and would eventually converge as the system reaches quasi-equilibrium (perhaps 5-10 days). In this context, the apparent discrepancies noted above do not unduly detract from the merit of this sample calculation.

Figure 28 shows the calculated $NPSH_{margin}$ for the first 24 hours and 30 days respectively following a loss-of-coolant accident (LOCA).

For Case 1 ABA M, the value of $NPSH_{available, SRP}$ is only 0.25 ft. Therefore, a small vertical offset notwithstanding, Figure 28 is essentially a representation of containment overpressure head as a function of time.

The RELAP5 code does not include sophisticated models for simulating transient containment thermal-hydraulics, such as those necessary to compute peak containment pressure and temperature. Since the calculation of NPSH margin takes as inputs the containment pressure and sump fluid temperature, the transient portion of the RELAP5 computation of NPSH margin should likewise not be expected to be highly accurate. This expectation is seemingly confirmed by Figure 28, which shows a sharp downward spike occurring at approximately 20 minutes, during which time the $NPSH_{margin}$ predicted by RELAP5 briefly drops below zero. It should be noted that the time of minimum $NPSH_{margin}$ is prior to the switchover to sump recirculation mode. As a result of the shortcomings of the RELAP5 code in modeling transient containment thermal-hydraulics, this code's predictions of $NPSH_{margin}$ are quite uncertain in the short-term (i.e., within approximately the first 24 hours after the accident, but particularly within the first several hours). However, as the purpose of the present calculation is to provide an estimate of the longer-term behavior of the $NPSH_{margin}$ over a period of days and weeks, this shortcoming can be overlooked. Once the significance of the transient effects has diminished, the RELAP5 code can effectively model the quasi-steady-state transfer of heat and mass in containment. Therefore, despite the noted deficiencies regarding transient effects, the RELAP5 code can effectively model the long-term containment pressure and sump fluid temperature with sufficient accuracy to adequately represent the long-term NPSH margin for a typical plant.

It should be noted that the $NPSH_{margin}$ does not include a reduction to account for a debris bed that may be present on the suction strainer.

There appears to be a slight inconsistency in the $NPSH_{required}$ data furnished by the licensee. Even if the observed inconsistency implies an error, however, the magnitude of the error would be very small (approximately 0.2 ft) and, thus, insignificant for the purpose of this calculation.

The amount of overpressure available may significantly exceed the design differential pressure of the suction strainers. For instance, one replacement suction strainer for a different plant has a design differential pressure of 5 psi (approximately 11.55 ft of head loss). For existing PWR sump screens, the design differential pressure may be significantly smaller than this value. If the structural failure of a suction strainer would occur at a differential pressure smaller than the available overpressure, then the actual margin provided by containment overpressure would be less than the amount calculated as being available. Detrimental consequences of sump screen structural failure could include the loss of sump recirculation and potential adverse effects to flowpaths being used to take suction from the sump. Investigation of these effects was not within the scope of this report.

It is further noted that containment overpressure would not be a source of margin for plants with partially submerged sump strainers, since the containment pressure does not act to help push water through partially submerged strainers. Therefore, when considering the failure mode of loss of flow, partially submerged strainers should still be assumed to fail once the head loss across the sump screen exceeds half the submerged height of the screen, whether or not overpressure is present. Further discussion of this failure mode associated with partially submerged sump screens is provided in Regulatory Guide 1.82, Revision 3.

In the long-term, for the sample calculation performed, approximately 30 ft of containment overpressure head exists over the majority of the 30 days following the LOCA. As qualified above, the available overpressure head could provide margin against head loss due to chemical effects and accumulating debris.

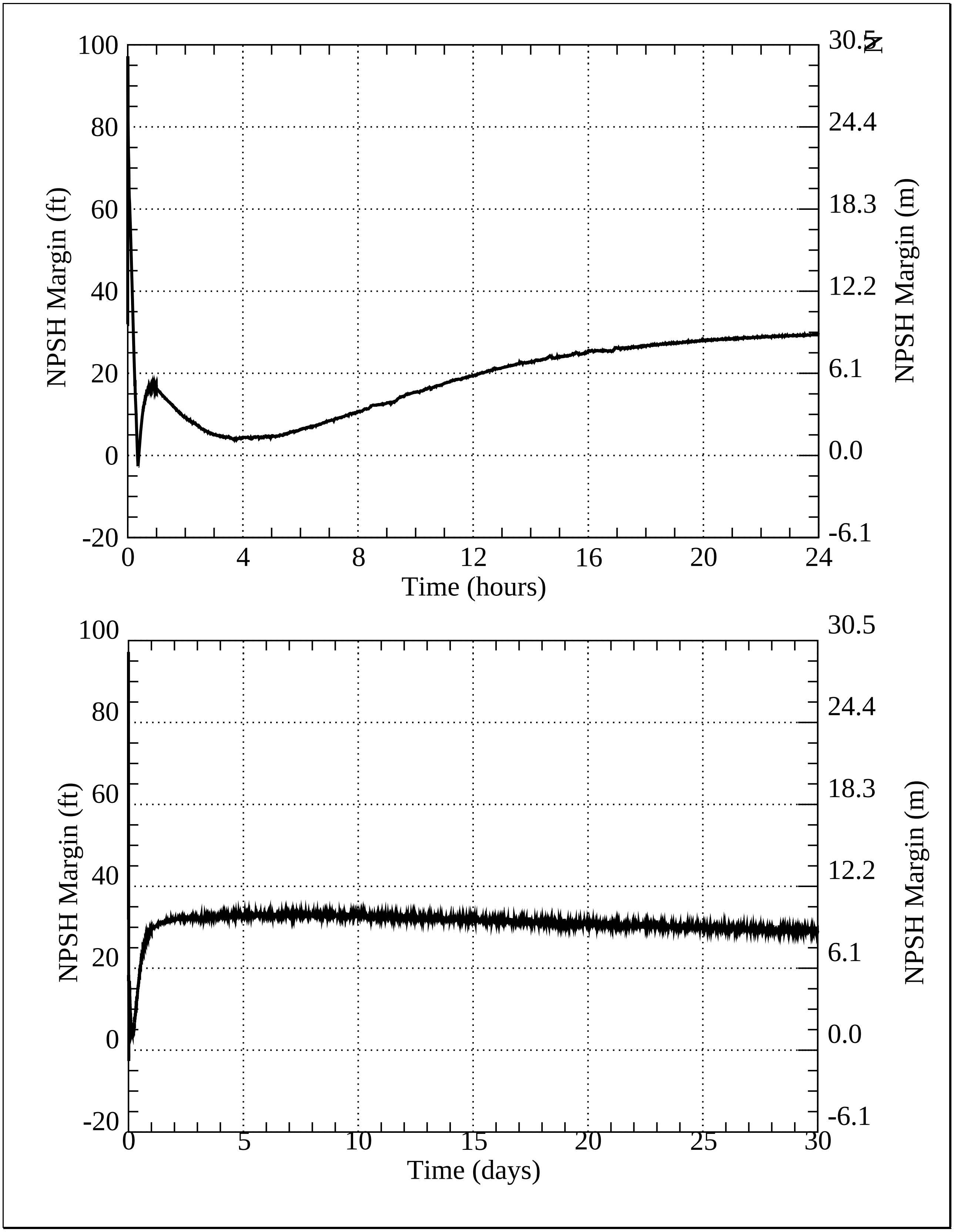

Figure 28: *NPSH Margin Sample Calculation, Case 1 ABA M*